Western Interstate Energy Board

Enhanced Distributed Solar Photovoltaic Deployment via Barrier Mitigation or Removal in the Western Interconnection

Final Technical Report

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EXECUTIVE SUMMARY

When the Western Interstate Energy Board's (WIEB's) *Enhanced Distributed Solar Photovoltaic Deployment* project started in 2017, the Western Electricity Coordinating Council (WECC) 2026 Common Case projected that distributed solar PV deployment in the Western U.S. would meet or exceed 16,106 MW of installed capacity by 2026. Of this total, 12,218 MW was projected to be deployed in California and another 3,888 MW was projected to be deployed across Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. However, WIEB recognized that barriers to distributed solar PV deployment could cause the region to fall short of these projections. With a better understanding of potential barriers to solar PV deployment in the West and the identification of potential mitigation measures, WIEB believed that western state policymakers and electric utility regulators could help to support solar PV deployment in their communities and across the West and, thereby, to help states, utilities, and electricity customers to better achieve their clean energy and carbon reduction goals.

WIEB's goal for the *Enhanced Distributed Solar Photovoltaic* project was to work with technical assistance providers (i.e., the National Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Laboratory (LBNL)) to identify potential barriers to distributed solar PV deployment in the Western U.S. and help states to mitigate or remove these barriers to ensure that the West could successfully meet or exceed 16,106 MW of installed capacity by 2026. To achieve this goal, WIEB identified two primary objectives for this project, which include the following:

1. Conduct analysis and develop strategies for Western U.S. electric power policymakers and regulators to mitigate or remove potential solar PV deployment barriers, including:
    - Interconnection Barriers (i.e., lengthy timelines and customer costs related to distributed solar PV interconnection)
    - Utility Rate Design Barriers
    - Reliability Barriers

2. Engage Western U.S. electric power policymakers and regulators in the:
    - Consideration of findings from the technical assistance providers' analysis and scenario planning; and
    - Development of possible strategies to mitigate or remove barriers to distributed solar PV deployment.

With funding from the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE), WIEB, NREL, and LBNL conducted innovative research and analysis on each of the three identified barriers to solar PV deployment in the West and produced eight final reports. Based upon the findings and conclusions of these final reports, WIEB, NREL, and LBNL developed mitigation measures and shared these findings, conclusions, and mitigation measures with state regulators and policymakers across the West.

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BACKGROUND

In 2017, the Western Electricity Coordinating Council (WECC) 2026 Common Case projected that distributed solar PV deployment in the Western U.S. would meet or exceed 16,106 MW of installed capacity by 2026. Of this total, 12,218 MW was projected to be deployed in California and another 3,888 MW was projected to be deployed across Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. However, WIEB recognized that barriers to distributed solar PV deployment could cause the region to fall short of these projections. WIEB identified three types of perceived barriers that might interfere with the deployment of distributed solar PV generation in the West, including: (1) interconnection barriers; (2) utility rate-design barriers; and (3) reliability barriers.

Interconnection Barriers to Solar PV Deployment

WIEB recognized that interconnection practices could present barriers to distributed solar PV deployment in the West. In recent years, the rapid adoption of customer-sited solar PV and growth in the number of requests to interconnect solar PV systems to the utility grid has raised new issues and challenges for PV installers, utilities, and PV customers who absorb the costs of interconnection challenges. It has also led to a variety of innovations and new approaches in assessing costs, grid conditions, and requirements for interconnecting distributed energy resources to the grid.

Several states—particularly those with the most active solar markets—have revised interconnection requirements, worked to streamline and automate interconnection processes, and taken a closer look at equity, cost, efficiency, and transparency throughout various stages of the interconnection process.

For this project, WIEB worked with NREL to conduct interviews with representatives of solar PV developers and electric utilities that operate in the West. Interviewees were asked to identify the top three barriers to interconnecting solar PV, unique challenges to installation in states where they operate, and potential solutions to these challenges.

Solar PV developers interviewed indicated that the most significant barriers were a lack of relevant information about the distribution grid, inconsistent or outdated equipment requirements, and differences in practices across utilities. Utilities had a different set of interconnection concerns related to solar PV and indicated that scheduling appointments to keep within timelines, allocating costs when upgrades were necessary, and the need for new requirements for solar PV coupled with storage presented the greatest challenges.

To examine these issues further, WIEB and NREL reviewed interconnection cost data for 92 solar PV systems across four western states to better understand the types and magnitude of interconnections costs. WIEB and NREL also examined interconnection policies and practices being implemented by states and utilities across the Nation to address emerging challenges associated with the increased volume of interconnection requests.

Utility Rate-Design Barriers to Solar PV Deployment

WIEB also recognized that utility rate-design could present barriers to distributed solar PV deployment in the West. Distributed solar PV (DPV) under net energy metering with volumetric retail electricity pricing (i.e., uniform compensation of generation in excess of consumption, regardless of its characteristics such as time of generation) has raised concerns among utilities and regulators. Electric investor-owned utilities (IOUs) are concerned about the effects of DPV on sales and future earnings opportunities from deferred or avoided capital investments under existing regulatory and business models. At the same time, utility regulators are concerned about possible increases in retail rates and cost-shifting from customers with DPV (i.e., participants) to non-DPV customers (i.e., non-participants). In instances where costs increase faster than sales, there is upward pressure on retail rates. Net Energy Metering (NEM) reforms have been proposed and, in certain cases, adopted by state public utility commissions. Most reforms change the DPV system payback periods and, thus, have the potential to reduce distributed solar PV deployment. Regulators must weigh utility and ratepayer concerns as they consider changes to NEM and retail rate design and, ultimately, they must make a determination that they believe serves the public interest.

In July 2019, LBNL published a report titled, *Current Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources*, discussing DER retail rate designs, NEM, and NEM alternatives. This qualitative study explored the implications of rate designs for distributed solar PV and other distributed energy resources. LBNL used a pro forma financial model—the FINancial impacts of Distributed Energy Resources (FINDER) model—to quantify the financial impacts of net-metered DPV on a prototypical Western IOU, to identify the key sensitivities and utility attributed driving lesser or greater magnitude of impacts, and to identify and assess the efficacy of strategies to mitigate financial impacts to help frame, organize, and inform ongoing discussions of NEM reforms among regulators, utilities, and other stakeholders.

Reliability Barriers to Solar PV Deployment

WIEB also recognized that reliability concerns could present barriers to distributed solar PV deployment in the West; these barriers are related to resource adequacy, system flexibility, and the potential for distributed energy resources (DERs) to impact larger power system stability.

Reliability Barriers - Resource Adequacy

Resource adequacy (i.e., ensuring a sufficiently low risk of available generation supply falling short of demand) is a key concern for all power system planners, operators, and load-serving entities. The North American Electric Reliability Corporation (NERC) produces three annual resource adequacy reports—including a summer assessment, a winter assessment, and overall long-term reliability report—to document the resource adequacy status of NERC-jurisdictional power systems and explore how well poised power systems are to provide affordable electricity at peak times, both now and into the future. NERC's reliability assessments primarily report resource adequacy in terms of planning reserve margins, which is the firm capacity over and above the peak load forecast and is typically expressed as a percentage of the peak load forecast.

Planning reserve margins are straightforward to compute and understand for systems dominated by fully dispatchable generators. However, with increasing penetrations of variable resources, key resource adequacy risks shift to phenomena not easily expressed as an extra quantity of generic capacity. These risks include correlated lulls in variable-generation output measured against time-varying load, as well as increasing risk related to outages of transmission links from renewable resources to load centers. This makes it difficult to fold variable generation into planning reserve margin frameworks. However, doing so is still attractive because of the relative simplicity of those frameworks as compared to fully accounting for reliable operations at hourly or finer resolution. The translation is often made by expressing variable-generation resources' contributions to meeting peak load as a capacity credit, that is, as a fraction of nameplate capacity that can be considered firm in the sense of contributing generation at times that help the system serve more load.

For this project, NREL assessed the ability of a capacity expansion model using such a planning reserve margin methodology to ensure resource adequacy under high penetrations of distributed and utility-scale solar PV, described methods for evaluating resource adequacy and capacity credit, applied probabilistic methods to evaluate the overall resource adequacy of those scenarios, as well as the contribution of variable-generation resources to meet peak load, and summarized findings related to planning for resource adequacy in the case of systems with high penetrations of solar PV.

Reliability Barriers – System Flexibility

As penetrations of variable renewable energy generation technologies such as wind and solar PV continue to increase across the United States, greater uncertainty and variability in net load often lead to concerns about how power systems may adapt. Operating the power grid requires balancing supply and demand over many timescales and in every instant. Demand is constantly changing, and as a result, supply must change as well. There is inherent flexibility in power systems through the conventional generator fleet (under least-cost unit commitment and economic dispatch), less-conventional generation sources (e.g., storage, demand response, concentrating solar power with thermal energy storage), and imports and exports with neighbors. However, renewable energy from variable resources like solar PV and wind can complicate system operation by increasing net load uncertainty and variability, potentially requiring larger quantities of operating reserves and increased ramps from the rest of the generator fleet. In short, renewable energy from variable resources often leads to a requirement for greater grid flexibility.

Previous work has considered various methods for quantifying flexibility. For this project, NREL analyzed system flexibility under high-penetration PV scenarios constructed for three focus regions in the western United States.

Reliability Barriers – DERs and Larger Power System Stability

DERs can also impact larger power system stability. The quantity of DERs in the West has increased substantially during the last two decades and how resources respond to power system disturbances has changed from minimally consequential to potentially critical. Transmission-level disturbances such as line and bus faults can negatively affect the voltage profile across vast regions of the Western Interconnection, with voltages propagating downward to the distribution system and causing adverse voltages on the terminals of many DERs, which might then trip offline, depending on implemented ride-through criteria.

For this project, NREL sought to improve modeling and understanding of DER response to regional voltage events (based on IEEE 1547 compliance). This report details a transmission and distribution dynamic modeling study that uses representative feeders in the West to investigate the performance of various IEEE 1547-2018 voltage ride-through performance categories. Three transmission areas within the Western Interconnection are investigated, including Southern California, Arizona, and Colorado. This report is intended to inform regulators and policymakers of the levels of ride-through coordination potentially necessary to maintain system reliability in cases with high DER penetration.

PROJECT OBJECTIVES

The goal of WIEB's *Enhanced Distributed Solar Photovoltaic Deployment* project was to mitigate or remove barriers to distributed solar photovoltaic (PV) deployment in the Western U.S. If the strategies developed in this project are used, WIEB expects that distributed solar PV deployment in the Western U.S. would successfully meet or exceed the projected deployment of 16,106 MW of installed capacity in 2026. Although this project had a western focus, the lessons learned can be applied in a broader, national application. By removing identified barriers to distributed solar PV deployment, the western states and the Nation will be better positioned to affordably and reliably achieve state and national carbon reduction and clean energy goals.

Through this project, WIEB and WIEB's technical assistance providers (i.e., the National Renewable Energy Laboratory (NREL) and the Lawrence Berkeley National Laboratory (LBNL)) conducted research on three types of perceived barriers to the deployment of distributed solar PV; barriers including: (1) interconnection barriers; (2) utility rate-design barriers; and (3) reliability barriers associated with the deployment of distributed solar PV generation in the West. WIEB, NREL, and LBNL worked to clearly define these perceived barriers, develop research plans, collect and analyze data, prepare research reports, define barrier mitigation measures, and to share the findings of this research with state policymakers and regulators in the West.

PROJECT RESULTS AND DISCUSSION

When this project started in 2017, it was WIEB's intention that, with a better understanding of perceived barriers to solar PV deployment, the identification of potential barrier mitigation measures, and sharing mitigation strategies with western state policymakers and electric utility regulators, distributed solar PV in the Western U.S. would meet or exceed 16,106 MW of installed capacity by 2026. WIEB identified ten tasks that would lead to the successful completion of this project. These tasks are discussed in turn below.

Task 1. Establish Technical Advisory Committees (TACs) –WIEB established three Technical Advisory Committees (TACs) to guide research on perceived interconnection, rate design, and reliability barriers to the deployment of distributed solar PV in the West. WIEB issued a public request for nominations of subject matter experts, evaluated the professional qualification of nominees, and formed a TAC for each perceived barrier comprised of individuals with subject matter expertise and knowledge in the specific area of interest. Milestones for this task included finalizing a list of members for each TAC.

Task 1 was successfully completed, with TACs for each barrier comprised of a variety of stakeholders, including representatives of western state energy offices, public utility commissions, utilities, solar sector firms, environmental organizations, and other entities. Due to their diverse and knowledgeable membership, these TACs provided valuable input and feedback to the project's technical assistance providers.

Task 2. Define Perceived Barriers to Deployment of Solar PV – WIEB and the technical assistance providers worked with members of the TACs to clearly define the nature of the three perceived barriers to the deployment of solar PV and to describe these barriers in terms of problem statements; noting, for example, that if a specific barrier is not adequately addressed, actual deployment of solar PV will not rise to forecasted levels in 2026.

Relying upon literature reviews and prior research, WIEB, NREL, and LBNL identified and drafted a list of barriers to solar PV deployment associated with interconnection processes, utility rate design, and reliability in the western U.S. With input from each TAC, WIEB and these technical assistance providers successfully finalized definitions for each of the perceived barriers, which include the following:

Interconnection Barriers

Interconnection Barriers – Uncertainty

1. Lack of interconnection standards can increase coordination/design burden on developer;
2. Difficulty obtaining utility interconnection documents can increase coordination/design burden on developer;
3. Lack of information about local grid leads to uncertainty in application review time, upgrade costs, ability to interconnect generally;
4. Lack of public project queue prevents assessment of time to review/approve, likelihood of upgrades; and
5. Lack of transparency in application review status prevents efficient scheduling of installation labor and material procurement and storage.

Interconnection Barriers – Delay

1. Length of time to process applications can hamper installer cash flow if materials procured in advance of application submission;
2. Incomplete applications can lead to unproductive wait times for the utility, installer, and customer;
3. Mismatch between complexity of project and level of review can impose additional time and utility work without adding real value;
4. Unbounded or lengthy reviews/studies can impact scheduling, hurt project economics;
5. Requirements for utility inspection, particularly for small systems, can impose unnecessary delays when systems are already installed;
6. Paperwork handling and other delays in permission to operate impose additional hardship as equipment/capital already deployed.

Interconnection Barriers – Cost

1. Interconnection standards with unnecessary equipment can raise costs
2. Submission through non-electronic methods can be more burdensome, costly, and poorly tracked;
3. High interconnection application fees can deter project proposal;
4. High costs for interconnection application review can increase costs to customer
5. High interconnection/system upgrade costs impose burden at a late stage of development;
6. Utilities may overrun their cost estimates for interconnection facilities or system upgrades, passing these costs on to customers; and
7. Last-in cost allocation mechanisms impose large costs on a small number of projects (rather than spreading across many), potentially leading to project abandonment.

Utility Rate-Design Barriers

1. Increased retail rates;
2. Cost shifting;
3. Reduced utility shareholder return on equity; and
4. Reduced utility earnings opportunities.

Reliability Barriers

Reliability Barriers – Bulk Dispatch

1. Increased ramping needs in morning and evening;
2. Solar generation uncertainty associated with cloud-cover;
3. Lack of visibility into distributed PV systems;
4. As currently implemented, automatic load shedding could end up exacerbating a system imbalance by disconnecting as much DPV generation as load; and
5. Management of generating units during periods of PV overgeneration mid-day.

Reliability Barriers – System Planning

1. Risk of inaccurately capturing the ability of PV and storage to contribute to system capacity;
2. Inability to use available DPV generation;
3. Black start planning is complicated by the presence of DPV;
4. Contractual limits on power factor at substation may conflict with DPV effects; and
5. Uncertainty about the amount and location of future DPV for proper planning and forecasting.

Reliability Barriers – Dynamic Stability

1. Non-synchronous generators may provide insufficient inertial response during the first few seconds after loss of generation;
2. Non-synchronous generators may provide insufficient primary frequency response during the first minute after loss of generation;
3. With more inverter-based generation, it may be more difficult to ensure transient stability, that is, the ability of the grid to successfully transition through a disturbance from more normal operation state another;
4. At high enough deployment levels, distributed generation control settings will impact bulk system performance in the face of disturbances; and
5. The advanced control schemes being developed for technologies such as PV, Wind, HVDC, and FACTS sometimes interact in undesirable ways.

Reliability Barriers – Distribution Grid Barriers

1. PV inverter settings may unduly exacerbate voltage conditions;
2. DPV complicates system protection coordination, relay sensitivity and safety

issues;
3. PV inverter settings may unduly exacerbate abnormal frequency conditions/events;
4. Sufficiently high PV penetrations result in backflow at distribution substations;
5. The power quality improvements that could be achieved by enabling advanced inverter settings are not valued in current market structures;
6. Local PV resource variability-induced ramping can impact voltage regulation equipment operations and power quality;
7. Advanced PV inverter operation to mitigate distribution level voltage issues may stress reactive power reserves on the bulk system; and
8. Advanced inverters may inadvertently interact with each other resulting in undesirable power oscillations.

These initial barrier descriptions served an important role in determining the scope and informing the development of a research plan for each perceived barrier category. Milestones for this task included finalizing descriptions of perceived interconnection, reliability, and rate design barriers.

Task 3. Develop Research Plans for Perceived Barriers to Deployment of Solar PV – WIEB and the technical assistance providers worked with members of each TAC to develop a written research plan to address each of three identified barriers to solar PV deployment in the West. These research plans clearly described the: (1) objectives of the research, (2) sources of data to be used, (3) research methods to be used, and (4) analyses to be performed. With input from each TAC, the technical assistance providers drafted and finalized a written research plan for each of the perceived barriers. Milestones for task 3 included finalizing research plans for each barrier. The TACs successfully finalized a research plan for each perceived barrier, completing an important step in determining specific data to be collected and shared with western states during the project's outreach phase. These research plans are summarized below.

Interconnection Barriers – Research Plan

1. <u>Barrier assessment and questionnaire</u>. NREL will obtain information from PV developers, utilities, and other stakeholders in Western states to identify the highest priority interconnection barriers in each state.
2. <u>Assessment of interconnection practices and procedures in the Western States</u>. NREL and WIEB will collect data and prepare a report that will review interconnection practices in Western states and explore emerging issues and best practices for reducing costs, delays, or uncertainty.
3. <u>Deeper dive analysis on upgrade cost issues</u>. NREL will explore cost-related issues in greater depth.

Utility Rate-Design Barriers – Research Plan

1. <u>Distributed solar PV deployment levels</u>. LBNL will study how increasing

penetrations of distributed solar PV affect the magnitude of utility-rate design impacts to shareholders and ratepayers; considering penetrations of 1.0% (low); 4.0% (medium); and 8.0% (high).
2. Prototypical Western utility characterization. LBNL will model a prototypical Western utility that is generally representative of an investor-owned utility in the region.
3. DER compensation and alternative regulatory/ratemaking approaches. LBNL will model a range of alternative DER compensation, ratemaking, and regulatory strategies based on the financial impacts at the low, medium, and high penetration targets.
4. Output metrics. The LBNL study will quantify financial impacts on shareholders and ratepayers and explore some of the tradeoffs associated with improving utility profitability at additional cost to ratepayers, and the impacts of strategies on simple payback times for DPV customers.

Reliability Barriers – Research Plan

1. Analysis of Ride-Through Distributed Energy Resource Performance Categories for the Western Interconnect. Provide guidance on technically appropriate performance categories and assess whether a Western Interconnect-wide performance category approach would be advantageous as compared to local performance specification based on more locally determined reliability concerns.
2. Planning for very high penetration systems. Examine several possible high-PV deployment pathways for three Western regions, and evaluate for which locations and PV penetration levels dynamic stability, ramping, DPV operations, and/or ensuring sufficient peak capacity may cause issues.

Task 4. Conduct Research on Perceived Barriers to Deployment of Solar PV –

The technical assistance providers conducted research and scenario analysis using established modeling approaches, collected and analyzed data, drafted findings and conclusions, responded to input from the TACs, and finalized the key findings and conclusions of their research on perceived barriers to deployment of solar PV in the western U.S. Milestones for this task included finalizing the findings and conclusions from research on each perceived barrier. The technical assistance providers completed this work, which then became the basis for the project's final eight research reports, which are identified and descripted under Task 5, below.

Interconnection Barriers – Research Approach

For the study of interconnection practices and procedures, NREL proposed to collect data from utilities and developers in the West through an email or online questionnaire and supplementing with interviews.

Utility Rate-Design Barriers – Research Approach

For the study of utility rate-design barriers, LBNL proposed an analytical approach for exploring the financial impacts of DPV on a prototypical Western utility and its ratepayers under a range of distributed energy resource (DER) compensation schemes and alternative utility regulatory and business models that might mitigate some or all the financial impacts. This analytical approach would not only characterize a generally representative utility in the West, but also consider some of the likely ratemaking and regulatory approaches implemented or under consideration in Western states.
For inputs and assumptions used in the pro forma financial model employed in this study (FINDER Model), LBNL would rely on publicly available data sources.

Reliability Barriers – Research Approach

For the analysis of ride-through distributed energy resource performance categories for the Western Interconnect, NREL proposed a co-simulation approach, combining positive sequency dynamic analysis of the Western Interconnect and quasi-static time-series (QSTS) distribution-system level analysis on representative feeders for three service territories, including Southern California Edison, Arizona Public Service, and Xcel. Existing dispatch scenarios for the Western Interconnect, would be leveraged to perform dynamic analysis of system faults and conventional generation trips. The time-series voltage profiles from the dynamic analysis, under a temporary fault condition, for specific substations which interconnect significant DER in each service territory investigated would then be used as an input to an unbalanced three-phase QSTS distribution system analysis of representative feeders. These feeders would be populated with many PV systems and each system would be modeled to implement various VRT and frequency ride-through (FRT) performance categories as specified in latest IEEE P1547 draft. QSTS analysis would help assess how much DER-based generation would disconnect for various transmission-level events. Iterations of the co-simulation would be used if it was determined that the loss of DER-based generation significantly changed the voltage/frequency responses determined by the transmission-level positive sequence dynamic analysis.

For its research on planning for very high penetration systems, NREL proposed three Resource Planning Models (e.g. Arizona, Colorado, and one TBD) to be run under several scenarios with increasing penetrations of PV, different proportions of DPV, and varying amounts of PV throughout the remainder of the Western Interconnect. The system evolution pathways thus constructed would then be examined to determine if there might be dynamic stability, ramping, DPV operations, or peak capacity issues at some point between the present and 2035. At least one potential issue would be chosen for each region and examined in depth. NREL would report out a) whether its current planning practices adequately addressed the issue up front, b) if there was an issue to mitigate, at least one way to do so, and c) how planners might adjust their practices to ensure they obtain reliable portfolios as more and more PV is deployed. The latter would include indications as to when, as a function of region and/or interconnection PV penetration, one should expect to pay more attention to dynamic stability, ramping, DPV operations, and/or methods for evaluating peak capacity.

Task 5. Prepare Research Reports on Perceived Barriers to Deployment of Solar PV

– Technical assistance providers for this project drafted and finalized research reports on interconnection, utility rate-design, and reliability barriers to the deployment of solar PV in the western U.S.

Reports – Interconnection Barriers to Solar PV Deployment

As noted above, NREL and the Interconnection Barrier TAC identified system upgrade costs and interconnection practices and procedures as important interconnection barriers to solar PV deployment in the West. NREL produced two reports to study and address these barriers.

- **NREL Report: *Review of Interconnection Practices and Costs in the Western States***

  The objective of this report was to evaluate the nature of barriers to interconnecting distributed PV, assess costs of interconnection, and compare interconnection practices across various states in the Western Interconnection. The report addresses practices for interconnecting both residential and commercial-scale PV systems to the distribution system.

  To understand interconnection challenges in the western states, the authors conducted interviews with representatives of PV developers and electric utilities that operate in the West. Interviewees were asked to identify the top three barriers to interconnecting PV, unique challenges to installation in states where they operate, and potential solutions to those challenges. Developers interviewed indicated that the most significant barriers are lack of relevant information about the distribution grid, inconsistent or outdated equipment requirements, and differences in practices across utilities. Utilities have a different set of interconnection concerns related to solar PV and the most frequently mentioned challenges are scheduling appointments to keep within timelines, allocating costs when upgrades are necessary, and the need for new requirements for solar PV coupled with storage.

  For this study, NREL obtained interconnection cost data for 92 solar PV systems ranging in size from 100 kW to 20 MW, across four western states where data were available. The objective was to provide perspective on the types and magnitude of interconnection costs, which are generally borne by the applicant. Analysis revealed that 43% of proposed systems required no network upgrades related to maintaining grid reliability. Where required, thermal impacts were the costliest impacts to mitigate, averaging around $1.2 million per project for which mitigation was required. The frequency of voltage, thermal, and protection impacts was similar across the studies examined, with voltage issues slightly more common. When aggregating the costs of all the proposed systems in this study, NREL found that network expansion costs were higher than the cost of any of the impact mitigation categories.

The study also compared interconnection practices across the western states, including those related to interconnection standards, customer service practices, and provisions that provide increased cost certainty to customers. Utility practices can, and in many cases do, exceed state mandates, but the focus here was on comparing state requirements.

Interconnection standards, application processing tracks, and technical screens.

Although most states have standardized interconnection requirements that are used across regulated utilities, just half of the states have specific requirements for non-exporting systems, and only a few states have developed specific guidance for the interconnection of storage or PV plus storage. With respect to application processing tracks, most states have different levels of review (simplified application, fast-track, supplemental review, and detailed study) based on project size and interconnection complexity; however, the review requirements and size thresholds for expedited review differ from state to state. Most states allow for simplified applications for systems 10–30 kW and smaller, although fast-track processes are often used for systems of 2–3 MW and smaller. A few technical screens, which are used to assess feeder conditions and characteristics at the point of interconnection to determine whether a proposed project would compromise system reliability, are used for fast-track review in all states with interconnection rules. These commonly used screens are: 1) the 15% annual peak load screen, 2) the short circuit capability screen, and 3) the service-to-transformer compatibility screen. Additionally, although many states include supplemental review for projects that fail fast-track screening, the supplemental review study process is often not clearly outlined in interconnection standards.

Customer service practices.

Many states have requirements that are intended to ensure that end-use customers (i.e., solar PV system owners) receive a minimum level of service during the interconnection process. Most commonly, states stipulate timelines for application review and approval and specify a dispute resolution mechanism in their interconnection rules. Additionally, some states require DER interconnection applications to be accessible online, and one state (California) requires utilities to report on their success in meeting timelines and to maintain a transparent queue of interconnection applications and the resulting projects. Although only Washington State explicitly requires that utility customers be able to submit applications online, 16 of the 25 utilities studied have an online portal that residential customers can use to submit applications, and 10 of the utilities have a portal for small commercial customers.

Cost-related provisions.

Several approaches have been used by states to increase cost certainty for customers who plan to interconnect solar PV systems. A majority of states have fixed application fees for small to mid-sized solar PV systems; for example, several states establish application fees of $100 or less for small solar PV systems. A few states require pre-application reports to be supplied to DER developers upon request, for all sizes of proposed systems. These reports are meant to provide important information to the utility customer and developer regarding potential adverse utility system impacts of a proposed solar PV system installation and the likelihood that utility distribution system upgrades might be required. In addition, California has adopted cost envelope provisions, which require utilities to provide upgrade cost estimates within specific thresholds (e.g., +/- 25%) early in the application process, and Utah limits developer study cost liability to within 25% of the initial study cost estimates. California also requires utilities to develop a Unit Cost Guide, or a list of costs associated with standard system upgrades, meant to provide greater transparency about electric delivery system upgrade costs.

Overall, interconnection requirements vary significantly from state to state. At the time this report was published, eight of eleven states had adopted policies to help simplify and speed up the interconnection application and study process, increase overall transparency, and reduce uncertainty surrounding the costs of interconnection from the local electric utility company.

- **NREL Report: *New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues***

  This report examines new policies and practices for interconnecting residential and commercial solar PV systems that are being implemented by states and utilities nationally to address emerging challenges with the increased volume of interconnection requests. The experience and lessons learned by these jurisdictions can prove useful to other regulators, policymakers, and utilities attempting to address similar challenges. This work builds on an earlier study (Bird et al. 2018) that reviewed interconnection practices and costs across the western states by providing more in-depth discussion of the design and implementation considerations of new interconnection policies and practices to share lessons learned.

  Issues covered in this report include understanding and allocating costs, evaluating grid conditions to inform solar PV siting, interconnecting solar PV plus storage, automating processes, and requiring the availability of advanced-inverter functions that can address grid concerns with greater penetrations of distributed, inverter-based resources. New interconnection policies and practices are being adopted or piloted in the following areas by states and utilities:

    - Cost certainty—A few states have implemented policies to help increase cost certainty for DER customers by having utilities provide cost estimates earlier in the process and limiting the customer's liability for upgrade costs to within a certain percentage (e.g., plus 25% of estimated costs) of the utility's upgrade cost estimate (Massachusetts and California). For smaller DER systems, some utilities provide certainty through fixed interconnection costs.

- Cost allocation—To address equity issues in the allocation of upgrade costs, several utilities and states are implementing new approaches to allocating costs of grid upgrades across projects (either a group of projects or across current and future projects), rather than imposing costs on a single project that triggers an upgrade.

- PV coupled with storage interconnection—With rapidly falling storage costs and greater interest in installing PV coupled with storage, several states are developing detailed standards that address the dispatch and operation of a combined solar PV and storage system. Evaluating grid impacts of solar PV systems coupled with storage can be more complex than for standalone PV because storage can operate as both a load and a generator and can have different grid impacts depending on how it is operated.

- Hosting capacity—Several states and utilities have undertaken processes to assess the grid hosting capacity, or the amount of distributed solar PV and other DERs that can be installed on a portion of the distribution system without triggering violations or grid upgrades. Hosting capacity analysis can be more accurate than the rule-of-thumb approaches often used in technical screens. California has undertaken a detailed analysis approach with an eye toward using the data to expedite interconnection and to aid in distribution system planning. New York, Hawaii, and Minnesota also have undertaken hosting-capacity assessments to aid in distribution-system planning and to provide potential DER projects with more information about grid conditions in advance of project initiation. New standards and codes—such as IEEE 1547-2018 and UL 1741SA—could positively impact hosting capacity on a significant number of feeders, especially when voltage excursions are the main area of concern. Smart inverters are required in California, Hawaii, and Massachusetts and in all likelihood will have a positive impact on the overall hosting capacity of many utility feeders. Additionally, DER technologies such as energy storage systems also might improve hosting-capacity limits by constraining the exports of distributed-generation DERs.

- Locational value—Some areas are developing methods to assess the locational value of PV and other DERs to identify locations where they could defer or avoid grid upgrades or provide grid services. Both New York and California are assessing locational value of DER. New York also has incorporated locational value elements in its value stack tariff for compensating exported power from DER, but commission staff are re-evaluating and assessing current approaches. Several other states are beginning to evaluate the opportunities that could arise with the use of non-wires alternatives (NWA) that could supplant some distribution, substation, and even transmission expansion plans.

- Advanced inverters—Several states are developing standards or requirements to take advantage of the functionality that advanced inverters can provide to contribute to grid reliability and communication with utilities. California, Hawaii, and Massachusetts now require all interconnecting DERs to have advanced inverters that can perform several functions (e.g., voltage and frequency ride-through, reactive power support—provided using UL 1741SA–listed inverters) to enhance grid reliability and improve coordination between DERs and system operators. ISO New England also has developed standards for inverter-based generation greater than 100 kW, and Hawaii requires ride-through capability for grid connected inverters.

- Automation—A variety of utilities that have experienced rapid growth in interconnection requests have undertaken efforts to streamline interconnection processes, often by implementing new software applications that increase automation and reduce processing time. Several utilities have reported significant labor cost savings and increased efficiency as a result of these changes.

The growing volume of interconnection requests has driven these new policies and practices in many instances. Jurisdictions that anticipate future growth might be able to learn from the experience of areas that have encountered challenges associated with rapid adoption and potentially could avoid some challenges before they emerge.

Report – Utility Rate-Design Barriers to Solar PV Deployment

As noted above, LBNL and the Utility Rate-Design Barrier TAC identified increased retail rates and cost shifting, reduced utility shareholder return on equity, and reduced utility earnings opportunities as important rate design barriers to utility support for, and customer adoption of, solar PV deployment in the West. LBNL produced a report on perceived utility rate-design barriers to solar PV deployment in the West.

- **LBNL Report: *Financial Impacts of Net-Metered DPV on a Prototypical Western Utility's Shareholders and Ratepayers***

  This study quantifies the financial impacts of net-metered solar DPV on a prototypical Western IOU and identifies the key sensitivities and utility attributes driving lesser or greater magnitude of impacts. The study also identifies and assesses the efficacy of strategies to mitigate financial impacts to help frame, organize, and inform ongoing discussions of NEM reforms among regulators, utilities, and other stakeholders. This study built on prior quantitative analysis of the financial impacts of net-metered PV (Satchwell et al., 2014; Satchwell et al., 2017) in two areas: assessing a wider range of sensitivities specific to the ability of DPV to avoid or defer utility costs (i.e., “solar DPV value”) and modeling mitigation strategies that have been proposed as specific alternatives to NEM.

Research scientists estimated the financial impacts using a pro forma financial model - the FINancial impacts of Distributed Energy Resources (FINDER) model - that calculates annual utility costs and revenues based on specified assumptions about the utility’s physical, financial, operating, and regulatory characteristics. The prototypical Western utility is characterized to generally represent a vertically-integrated IOU in the region based on publicly available data of financial, physical, and operating characteristics. Financial impacts are quantified at three solar DPV deployment levels (i.e., 1%, 4%, and 8% of 2027 retail sales) representing the range of forecasted solar DPV deployment among Western states. This study also analyzes several sensitivity cases with different assumptions about the value of solar DPV than what is assumed in the base cases. Finally, the study analyzes several ratemaking and regulatory measures for mitigating the potential negative financial impacts on utility shareholders, specifically net billing at avoided cost rate, NEM with a grid access charge, and an increased monthly customer charge for residential and commercial customers.

The study makes several important findings about the financial impacts of net-metered DPV on utility shareholders and ratepayers:

- First, these impacts on shareholders and ratepayers increase as the level of solar DPV deployment increases, though the magnitude is small even at high solar DPV penetration levels (8%). Because most western utilities currently have distributed generation deployments less than 1% of annual retail sales, policymakers and regulators likely have time to study and deliberate changes to NEM before observing material financial impacts.

- Second, the study explicitly links different estimates of solar DPV value to shareholder and ratepayer impacts and finds that even rather dramatic changes in solar DPV value result in modest changes to shareholder and ratepayer impacts. Also, the range of financial impacts under alternative DPV value assumptions are greater for shareholders than ratepayers on a percentage basis and driven by differences in the amount of incremental CapEx that is deferred, as well as the amount of incremental distribution OpEx that is incurred.

- Third, the mitigation cases demonstrate that what constitutes a financial impact from a particular perspective matters. While all the mitigation cases improved utility earnings, return on equity (ROE), and average non-participating customer bills (relative to the case with NEM only), average solar DPV participating customer bills increased further and, in some cases (i.e., grid access charge and 30% electricity export at avoided cost), pushed solar DPV system payback times beyond the system lifetime.

Regulators and policymakers may improve their understanding of multiple perspectives by incorporating feedback effects between changes in rate design or compensation mechanisms and solar DPV deployment rates.

Reports – Reliability Barriers to Solar PV Deployment

Finally, as noted above, NREL and the Reliability Barrier TAC identified bulk dispatch, system planning, dynamic stability, and distribution grid barriers as important reliability barriers to solar PV deployment in the West. NREL also produced four reports and an appendix on perceived reliability barriers to solar PV deployment in the West.

- **NREL Report: *Simulating Distributed Energy Resource Responses to Transmission System-Level Faults Considering IEEE 1547 Performance Categories on Three Major WECC Transmission Paths***

  This report seeks to improve modeling and understanding of DER response to regional voltage events, to properly identify DER requirements, and to derive an anticipated DER response based on IEEE 1547 compliance, thereby improving DER voltage ride-through performance and preventing DERs from unnecessarily tripping offline and further impacting power system voltage.

  Most interconnections of DERs in the United States adhere to the Institute of Electrical and Electronics Engineers 1547 standard (IEEE 1547). Following the release of the first version in 2003, commanded inverter operation during power system disturbances were found to vary widely because of the range of allowable responses outlined in the standard as well as various manufacturer interpretations. With the realization of larger penetrations of DERs than originally envisioned in the original standard, the impacts of these various responses became problematic from a power system reliability perspective. The updated version of the standard, IEEE 1547-2018, was released in April 2018 in part to more precisely define a DER's appropriate response during power system disturbances. IEEE 1547-2018 has defined performance categories that are effectively a menu of ride-through characteristics that can be applied to various DER technologies or for various overall DER penetration scenarios. This research highlights the various responses, showing the aggregate output of 6,150 inverters for three different categories of ride-through criteria compliant with a category of IEEE 1547-2018 and a worst-case scenario (lowest ride-through v performance likely) for IEEE 1547-2003. The results were generated from 123 individual distribution circuit simulations loosely co-simulated with a transmission simulation investigating the power system response to a specific event. The results show significant differences in the modeled amount of DER generation lost immediately following and up to 30 seconds after the transmission-level fault occurs, demonstrating the potential widespread impact of transmission-level faults on DERs, as well as the capability of new IEEE 1547- 2018 ride-through performance categories to largely mitigate widespread DER generation loss.

  This work also presents the results of a Western Interconnection transfer path contingency study using General Electric's Positive Sequence Load Flow (PSLF) dynamic transmission system modeling tool. Metrics developed from this study combine the magnitude of the voltage variation with the amount of DER located at every node within the model to generate location-relevant scores indicative of how system faults anywhere in the Western Interconnection might cause unintended DER losses. This study found a number of faults on transfer paths within the Western Interconnection that could have a significant impact on DERs. From this initial study, three regions were studied within the Western Interconnection for further investigation: the Front Range of Colorado; the Greater Phoenix, Arizona area; and Southern California. Within each region, the transfer path was selected that generated the largest effect on system-wide voltage profiles to examine the sensitivity of the DER ride-through response for various IEEE 1547 performance categories. The transfer paths analyzed include Path 36 within Xcel Energy's territory, Path 54 within the Arizona Public Service (APS) territory, and Path 61 within the Southern California Edison (SCE) territory. The impact of the considerable voltage diversity present in the distribution system, and thus at the terminals of the various DERs present in a system, were modeled. These distribution-level models were analyzed using quasi-static time-series (QSTS) simulations in OpenDSS augmented with controlled inverter responses adherent to the pertinent ride-though performance category being evaluated. Finally, to assess the impact of these various performance categories on the overall power system stability, the OpenDSS results for the amount of DER that would trip offline or resume operation as a function of time were used to control the modeled DER-based generation in PSLF during a resimulation of the transmission system subjected to the same fault scenario.

The key findings of this research effort are summarized in the following six bullet items:

- Under heavy loading conditions representative of summer peak load in the Western Interconnection, the potential for widespread influence on voltage profiles following a transmission-level fault is significant. This highlights the potential for large losses of DERs depending on the implemented low-voltage ride-through criteria. Even with this large influence, however, the colocation of the fault with high DER penetrations is the primary factor when considering potential generation losses caused by faults.

- The newly introduced volt-sec and volt-sec-DG metrics provide suitable analysis tools for making relative comparisons of the influence of a variety of transmission-level faults on the overall power system voltage profiles. In particular, the volt-sec-DG metric effectively highlights the relative impact of these faults on potential DER loss.

- The specific performance of DERs during fault conditions can have a large impact on the recovery of the power system. This highlights the importance of understanding the true operation of inverter-based generation during power system transient events and the need for improved models.

- FIDVR events generate persistent low-voltage profiles at distribution voltage levels, which can in some instances persist beyond the trip times specified in the IEEE-2018 ride-through criteria, leading to the loss of DER generation.

- The IEEE 1547-2003 standard allows for a nearly immediate momentary reduction in the power output of DERs for relatively small voltage deviations from nominal, which can potentially result in a large loss of generation. For instance, the large penetrations of DERs in California lead to a nearly 4 GW loss of generation for specific faults in Southern California. Other interpretations or implementations of IEEE 1547-2003 could allow significant voltage ride-through capability, greatly reducing this potential generation loss.

- Performance categories I and II from IEEE 1547-2018 yield similar aggregate DER real power responses and similar overall system recovery characteristics. Implementation of the Category III ride-through criteria of IEEE 1547-2018 yields respectively smaller total real power output reductions.

- **NREL Report: *Managing Solar Photovoltaic Integration in the Western United States: Resource Adequacy Considerations***

  This study examines the impact of reserve margin-based reliability assessment, as commonly used in capacity expansion models, on planning resource-adequate power systems under high penetrations of solar photovoltaics (PV). As a generation resource, solar PV is operationally different from the conventional dispatchable resources for which most capacity expansion models were designed. The question this study attempts to answer is whether large amounts of solar PV on a system (in this case, the Western Interconnection of North America) would bias the results of conventional reserve margin-based capacity expansion modeling towards an over- or under-provisioning of resource adequacy.

  This analysis used NREL's Resource Planning Model (RPM) for capacity expansion modeling and NREL's Probabilistic Resource Adequacy Suite (PRAS) for resource adequacy assessment. RPM uses a reserve margin requirement to enforce resource adequacy. PRAS, a collection of tools for studying the resource adequacy of power systems and the adequacy contributions of individual resources on a probabilistic basis, was used to compute multiple resource adequacy metrics 40,000 simulated scenarios and system representations with differing regional detail. In all cases, including high solar PV penetrations (up to 33% annual generation from solar PV, interconnection-wide), RPM was able to produce resource-adequate systems as measured by normalized expected unserved energy and loss-of-load expectation results from PRAS.

The accuracy of reserve margin approaches depends heavily on the underlying assumptions informing the capacity credit assigned to variable and energy-limited resources, particularly when such resources are abundant in the modeled system. RPM's standard methodology for estimating variable and flexible resources' capacity contributions, which is based on the top 100 hours of net load, did not appear to systematically undervalue or overvalue variable generation relative to a more rigorous equivalent firm capacity assessment using PRAS, although both over- and under-valuations were observed in specific scenarios. In the worst cases, the top 100-hour method underestimated the equivalent firm capacity of PV by two percentage points, and overestimated the equivalent firm capacity of PV by five percentage points. Calculating capacity contributions based on the top 10 hours of net load systematically underestimated equivalent firm capacities at more modest PV penetrations, but was often a better approximation of equivalent firm capacity than the current 100-hour approach in scenarios with higher PV penetrations.

- **NREL Report: *Managing Solar Photovoltaic Integration in the Western United States: Power System Flexibility Requirements and Supply***

In this analysis, NREL created an open-source tool to analyze the flexibility of the results of PLEXOS, a commercial unit commitment and economic dispatch tool. The tool assesses the flexibility requirements (or demand) of a system through a net load analysis. The constraints and limitations of each generator are then considered to determine the availability (or supply) of flexibility. Then, the supply and demand of flexibility are compared to gain a more complete picture of potential flexibility concerns.

NREL applied this open-source tool to high-penetration solar PV scenarios constructed for three focus regions in the western United States defined using the Resource Planning Model (RPM) capacity expansion modeling tool: RPM-Oregon, RPM-Colorado, and RPM-Arizona. Generally, NREL found few flexibility concerns, as the western United States represents a large and interconnected power system with significant inherent flexibility. In addition, the solar PV scenarios analyzed are generally high on capacity, leaving plenty of ramping ability on the system. The study did find that for each focus region, the impact of imports on meeting ramping needs is essential. This means the solar PV integration in each focus region impacts the entire rest of the system. Each system has different dominant sources of flexibility. The conventional generator fleet (especially coal and gas combined-cycle technologies) as well as less-conventional sources such as storage are all shown to be important sources of flexibility. In reality, none of the three focus regions likely will deploy solar PV in isolation, meaning the ability of imports and exports to provide flexibility may be considerably different in scenarios with strong solar PV deployment in every region.

Overall, the framework will be useful in future analysis of other system evolutions to identify whether and how flexibility may constrain the successful deployment of variable generation technologies.

- **NREL Report: *Behind-the-Meter Solar Accounting in Renewable Portfolio Standards***

This report explores how two renewable portfolio standard (RPS) design elements can influence the interaction of behind-the-meter (BTM) solar PV and total renewable generation, including: 1) whether renewable energy certificates (RECs) from BTM solar PV can be used for RPS compliance, and 2) whether load served by generation from BTM PV count as load covered by the RPS. These two elements combine into four possible accounting options. This report characterizes the implications of each under the simplifying assumptions that the RPS is binding and the BTM solar PV RECs are used for compliance when allowed. For example, if load served by BTM solar PV generation counts toward the RPS load and BTM solar PV RECs cannot be used for compliance, the presence of BTM does not change the amount of RECs that the utility is required to retire, and yet additional RECs will be retired by the BTM solar PV owner—therefore, the total amount of renewable generation would increase on a 1:1 basis with the BTM solar PV generation. In contrast, under a common RPS design in which BTM solar PV RECs can be used for compliance and the load served by BTM solar PV generation is not covered by the RPS, the presence of BTM solar PV and transfer of RECs for compliance can actually decrease the total amount of renewable generation in the state, relative to a situation in which there is no BTM solar PV.

- **NREL Report (Appendix): *Managing Solar Photovoltaic Integration in the Western United States Appendix: Reference and High Solar Photovoltaic Scenarios for Three Regions***

This slide contains Resource Planning Model (RPM) inputs, scenario framework, and results for RPM-Arizona, RPM-Colorado, and RPM-Oregon. The deck is an appendix to the paper series (Managing Solar Photovoltaic Integration in the Western United States: Resource Adequacy Considerations, Managing Solar Photovoltaic Integration in the Western United States: Power System Flexibility Requirements and Supply, and Behind-the-Meter Solar Accounting in Renewable Portfolio Standards), which examines potential challenges related to planning future power systems with higher solar PV penetrations. These two papers use the scenarios presented is the slide deck as their starting point for analysis.

These NREL and LBNL reports became the basis for WIEB's state outreach on the mitigation of barriers to solar PV deployment in the West. Milestones for Task 5 included finalizing reports on each of the perceived barriers.

Task 6. Establish Strategy Advisory Committees (SAC) – WIEB's initial plan was to establish three Strategy Advisory Committees (SACs) to guide state outreach on mitigation of each of the three barriers to the deployment of distributed solar PV. Each SAC was to be comprised of individuals having knowledge of state regulatory or legislative processes in the specific area of interest. Milestones for the task included finalizing a list of SAC members for each perceived barrier.

WIEB realized that it was more effective to engage representatives of each state on an individual basis and to specifically tailor state outreach plans and presentation materials to best reflect each state's interests and needs. In preparing for state outreach, WIEB worked directly with western state energy offices (SEO) to identify specific areas of interest and to gain awareness of potential areas of conflicts (e.g., public utility commission proceedings).

Task 7. Define Mitigation Measures for Barriers to Deployment of Solar PV –

Observations and options that states can use to mitigate interconnection, utility rate design, and reliability barriers to the deployment of solar PV were developed based on the findings and conclusions in the reports on perceived barriers.

Mitigating Interconnection Barriers

Regulators and policymakers can consider:

- Adopting a statewide interconnection standard, if one is not already in place.
- Including specific requirements to approve interconnection of no-exporting PV systems, which could reduce technical review requirements for those systems.
- Adopting a more transparent supplemental review study process.
- In states with high penetrations of PV on a number of feeders, maintaining a publicly-available interconnection queue to help developers identify feeders that are less likely to require upgrades to connect new projects.
- If non-compliance with timeline requirements is an issue, requiring utilities to regularly report timeline performance.
- In states that do not have fixed application fees, adopting fixed processing fees for the subset of smaller and less complex projects.
- Requiring utilities to offer pre-application reports to allow developers to request information about the system potentially impacted by a proposed project, to help assess the likelihood that costly upgrades would be required.
- In states where distribution upgrades ae required to connect some projects, adopting a policy that helps reduce uncertainty around potential upgrade cost overruns.
- In states with higher penetrations of DERs on some feeders, adopting policies that allocate upgrade costs over a group of projects, rather than only to the "cost causer."
- With regard to incorporating storage into interconnection standards, adding storage to the definition of a generator or clarifying how to credit the output of a net metered PV system that is connected alongside storage.
- In states with higher or growing penetrations of DERs, employing hosting capacity analysis to streamline technical review of interconnection requests, help developers target sections of the grid with available capacity, and/or inform distribution system planning.

- Whether any potential use cases related to locational net benefit analysis, such as distribution investment deferral, could increase the benefits of deployment to utilities and their customers.

Mitigating Utility Rate-Design Barriers

Regulators and policymakers can consider:

- Incorporating feedback effect on DPV deployment due to changes in rate design and/or compensation mechanisms.
- Determining the appropriate treatment of grid charges in rate setting.
- Evaluating the impacts of mitigation scenarios and include an assessment of the distribution of bill impacts on participants and non-participants.

Reliability Barriers - Resource Adequacy Findings

- Larger planning reserve margins do not always correspond to improved probabilistic resource adequacy metrics.
- The choice of capacity credit calculation method can influence assigned resource contributions.

Reliability Barriers – System Flexibility Findings

- Storage will provide an important source of system flexibility as penetrations of solar PV and other variable generation resources increase and net load shapes change.

Mitigating Reliability Barriers – DERs and Larger Power System Stability

- IEEE 1547-2018 Category III keeps the greatest amount of distributed generation online during a Fault Induced Delayed Voltage Recover event.

Milestones for the task included finalizing descriptions of mitigation measures for each of the perceived barriers.

Task 8. Develop State Outreach Plans for Mitigation of Barriers to Deployment of Solar PV – As part of this project, WEIB worked with western state energy offices (SEOs) to develop an outreach plan, to produce a meeting agenda tailored to the state's interests, and to inform the development of presentation materials for each state. Milestones for the task included finalizing an agenda for each state.

Task 9. Prepare State Outreach Materials on Mitigation of Barriers to

Deployment of Solar PV – Based upon input from the SEOs and individual state outreach plans, WIEB worked with the technical assistance providers to finalize state outreach materials, which described the perceived barriers to solar PV deployment, highlighted the findings and conclusions of the project's research efforts, and identified observations and options that states can use to mitigate such barriers to deployment in the western U.S. Milestones for the task included finalizing presentation materials on each of the perceived barriers. With input from the SEO's and technical assistance providers, WIEB successfully finalized presentation materials for each state meeting.

WIEB worked with NREL and LBNL to produce a tailored set of presentation materials for each state. This approach of developing state-tailored presentations was not initially contemplated when the project began. However, given that western states are confronting different conditions, working on different timelines, and working to achieve different objectives, it was very important develop each state outreach plan, presentation, and recommendations to reflect these differences and to provide timely and meaningful recommendations.

WIEB also decided to conduct both a leadership session and a technical session for each state. Technical sessions, tailored to technical staff, were longer and significantly more detailed. WIEB feels that this approach successfully provided western state energy office directors and public utility commissions with a timely and high-level overview of the project findings and recommendations, but also provided additional details to the technical staff that are charged with advising directors and commissioners.

Task 10. Conduct State Outreach on Mitigation of Barriers to Deployment of Solar PV – In completing this project, WIEB and the technical assistance providers met with regulators and policymakers from eleven states in western U.S. to disseminate and discuss observations and options for mitigating barriers to deployment of solar PV. Project representatives met separately with each western state, including Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming. Policymakers and regulators were able to provide feedback to WIEB on the usefulness of the project's outreach and to schedule follow-up meetings via conference call to receive clarification or further information on specific barriers or mitigation measures. Milestones for this task included completing state outreach on each of the perceived barriers.

WIEB worked with SEOs to invite state public utility commission (PUC) commissioners and staff to attend a joint SEO-PUC meeting, to develop a meeting agenda, and to prepare meeting materials. This approach was helpful to providing meaningful content and recommendations to each state, in a venue and format designed to accommodate both policymakers and regulators.

WIEB found that bringing state policymakers and regulators together in a common forum to discuss the results and recommendations from the project provided an opportunity—in many cases—for policymakers and regulators to meet one another and created a robust and successful dialogue on the presentation content. WIEB believes that this approach opened a dialogue between some western state energy offices and public utility commissions that is still ongoing and continues to be beneficial to those states.

However, there were challenges as well. WIEB planned to conduct each of these meetings in person and made good progress initially, conducting in-person meetings with nine of eleven western states to discuss Interconnection Barriers and opportunities to mitigate those barriers. However, due to COVID-19-related health concerns and travel restrictions, WIEB was unable to complete its outreach effort in-person. Instead, WIEB completed its outreach via webinar, with good attendance from western SEO directors and PUC commissioners. WIEB successfully presented findings, results, and mitigation measures to SEO directors, PUC commissioners, and staff in Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming. However, having met with state policymakers and regulators both in-person and virtually, WIEB cannot emphasize enough the importance of conducting these meetings in person when possible; in-person meetings build a greater level of trust, rapport, and ongoing partnerships.

To meet the Go/No-Go decision criteria and proceed from BP1 to BP2, WIEB planned to establish a TAC for each of the three perceived barriers, define the perceived barriers, and finalize a research plan for each for each of the perceived barriers that could be expected to produce meaningful results and have the potential to improve strategies for mitigating interconnection barriers to the deployment of solar PV. WIEB successfully created a TAC for each perceived barrier, comprised of a variety of stakeholders with a broad and diverse understanding of public policy, electric utility regulation, solar energy, environmental issues, etc. With these TACs, WIEB and the technical assistance providers were able to finalize a robust research plan for each perceived barrier, identifying data to be collected and shared with western states during the project's outreach phase.

To meet the Go/No-Go decision criteria and proceed from BP2 to BP3, WIEB planned to establish a SAC for each of the three perceived barriers, define mitigation measures to be used to address the perceived barriers, and develop state outreach plans that could be expected to produce meaningful results that have the potential to improve strategies for mitigating barriers to the deployment of solar PV. As noted above, WIEB came to realize that it was more effective to engage representatives of each state on an individual basis and to specifically tailor state outreach plans and presentation materials to best reflect each state's interests and needs. In preparing for state outreach, WIEB successfully worked with western state energy offices (SEO) to identify specific areas of interest, to gain awareness of potential areas of conflicts (e.g., public utility commission proceedings), and to conduct state outreach meetings for state energy offices and public utility commissions.

SIGNIFICANT ACCOMPLISHMENTS AND CONCLUSIONS

WIEB's primary objective for the *Enhanced Distributed Solar Photovoltaic Deployment* project was to ensure that distributed solar PV in the Western U.S. would meet or exceed 16,106 MW of installed capacity by 2026. Through the project, WIEB engaged eleven western states in an important dialogue about potential barriers to solar PV deployment in the West and opportunities to mitigate these barriers.

WIEB, NREL, and LBNL conducted innovative research and analysis on each of the identified barriers and produced eight final reports analyzing interconnection, utility rate-design, and reliability barriers to solar PV deployment in the West. Based upon the findings and conclusions of these final reports, WIEB, NREL, and LBNL developed and shared its findings, conclusions, and mitigation strategies with state regulators and policymakers across the West. Where states were already contemplating distributed solar PV, WIEB kept the dialogue going and highlighted new considerations. Where states were not contemplating distributed solar PV, WIEB helped to initiate that dialogue and highlighted important issues for future consideration.

As the western electric system continues to change, new opportunities and challenges will continue to arise. It will be important to continue to model the expansion of distributed solar PV in the West and to keep states apprised of potential barriers to deployment. WIEB's project was successful in bringing the study results and recommendations to western states and to encouraging an ongoing partnership and dialogue between state energy offices and public utility commissions. As noted above, WIEB found that bringing state policymakers and regulators together in a common forum to discuss the results and recommendations from the project provided an opportunity for policymakers and regulators to meet one another and created a robust and successful dialogue on the presentation content. WIEB believes that this approach opened a dialogue between some western state energy offices and public utility commissions that is still ongoing and continues to be beneficial to those states. There is more work to be done to support these ongoing collaborations; collaborations that could be strengthened through ongoing state engagement, discussion, and sharing of U.S. DOE reports through a regional entity such as WIEB. These dialogues will be important to supporting timely, affordable, and reliable deployment of solar PV and, thereby, to helping states, utilities, and electricity customers to better achieve their clean energy and carbon reduction goals.

Today, installed distributed solar PV is being deployed at an increased rate and, in 2019, capacity in the West exceeded 12,000 MW. Based on current trajectories, the West will exceed the 2026 target ahead of schedule, possibly by 2022. This trend can be attributed to a variety of factors including state, local, utility, and industry clean and renewable energy goals. However, the barriers to solar PV deployment identified in this project will still need to be resolved and the observations and options identified in this project will be useful to ensuring continued growth.

PUBLICATIONS

Interconnection Barrier Research Reports

- ***NREL Report: Review of Interconnection Practices and Costs in the Western States -*** This report reviews interconnection rules and practices in western states and across utility jurisdictions. Additionally, it highlights practices that may pose a barrier to deployment and identifies potential best practices for interconnection. https://www.westernenergyboard.org/wp-content/uploads/2018-nrel-wieb-report-on-review-of-interconnection-practices-and-costs-in-western-states.pdf

- ***NREL Report: New Approaches to Distributed PV Interconnection: Implementation Considerations for Addressing Emerging Issues -*** This report examines emerging issues and policy innovations associated with interconnecting residential- and commercial-scale PV to facilitate sharing of lessons learned and best practices across jurisdictions. https://www.westernenergyboard.org/wp-content/uploads/2019-nrel-wieb-report-on-new-approaches-to-distributed-pv-interconnection-implementation-considerations.pdf

Utility Rate Design Barrier Research Reports

- ***LBNL Report: Financial Impacts of Net-Metered DPV on a Prototypical Western Utility's Shareholders and Ratepayers -*** This report quantifies the financial impacts of net-metered DPB on a prototypical western IOU and identifies key sensitivities and utility attributes driving a lesser or greater magnitude of financial impacts. https://www.westernenergyboard.org/wp-content/uploads/09-2019-lbnl-report-financial-impacts-of-net-metered-dpv-final.pdf

Reliability Barrier Research Reports

- ***NREL Report: Simulating Distributed Energy Resource Responses to transmission System-Level Faults Considering IEEE 1547 Performance Categories on three Major WECC Transmission Paths -*** This report seeks to improve the modeling and understanding of DER response to regional voltage events, to properly identify DER requirements, and to derive an anticipated DER response based on IEEE 1547 compliance, thereby improving DER voltage ride-through performance and preventing DERs from unnecessarily tripping offline and further impacting power system voltage. https://www.westernenergyboard.org/wp-content/uploads/2020-nrel-report-simulating-distributed-energy-resource-responses-to-transmission-system-level-faults-ieee-1547.pdf

- ***NREL Report: Managing Solar Photovoltaic Integration in the Western United States: Resource Adequacy Considerations -*** This report provides a probabilistic resource adequacy assessment of high PV penetration scenarios and comparison to planning reserve margin approaches using capacity credit approximation methods. https://www.westernenergyboard.org/wp-content/uploads/2020-nrel-report-managing-solar-photovoltaic-integration-resource-adequacy-considerations.pdf

- ***NREL Report: Managing Solar Photovoltaic Integration in the Western United States: Power System Flexibility Requirements and Supply -*** This report provides an assessment of net load ramping needs under high-penetration PV scenarios in the western United States and the resources available to provide necessary power system flexibility upward and downward ramping at different timescales. https://www.westernenergyboard.org/wp-content/uploads/2020-nrel-report-western-solar-photovoltaic-integration-power-system-flexibility-supply.pdf

- ***NREL Report: Behind-the-Meter Solar Accounting in Renewable Portfolio Standards -*** This report explores how two renewable portfolio standard design elements can influence the interaction of behind-the-meter PV and total renewable generation. https://www.westernenergyboard.org/wp-content/uploads/2020-nrel-report-behind-the-meter-solar-accounting.pdf

- ***NREL Report (Appendix): Managing Solar Photovoltaic Integration in the Western United States Appendix: Reference and High Solar Photovoltaic Scenarios for Three Regions -*** This appendix contains Resource planning model (RPM) inputs, scenario framework, and results for RPM-Arizona, RPM-Colorado, and RPM-Oregon; two of the papers in the series use these scenarios as their starting point for analysis. https://www.westernenergyboard.org/wp-content/uploads/2020-nrel-report-managing-solar-photovoltaic-integration-appendix.pdf

Additional Resources

- ***NREL Article: Stability and control of power systems with high penetrations of inverter-based resources: An accessible review of current knowledge and open questions*** - This paper explores current knowledge and open research questions concerning the interplay between inverter-based resources (IBRs) (e.g., wind and solar PV) and cycle-to-second-scale power system dynamics, with a focus on how stability and control may be impacted or need to be achieved differently when there are high instantaneous penetrations of IBRs across and interconnection. https://www.sciencedirect.com/science/article/abs/pii/S0038092X20305442?via%3Dihub

PATH FORWARD

The innovative research and analysis conducted by WIEB, NREL, and LBNL with respect to potential barriers to solar PV deployment in the West, the modeling done to support this research and analysis, and the eight reports produced as a result of this effort will support continued deployment and higher penetrations of distributed solar PV in the Western Interconnection. WIEB will continue to share the information gained from this effort with its state partners.

As western states work to achieve their clean and renewable energy goals and penetrations of variable energy resources such as distributed solar PV increase, flexible and dispatchable capacity will become increasingly important to maintaining electric system reliability and supporting resource adequacy across the region. Energy storage—including short duration energy storage and long duration energy storage—could help to avoid curtailment and serve as an important source of the capacity and system flexibility as traditional baseload resources are retired. However, additional research and accurate modeling of energy storage resources, especially modeling of LDES resources, will be important to informing resource planning efforts. Additionally, continuing to work with state energy offices and public utility commissions will be important to help states, utilities, and electricity customers to stay informed and to achieve their clean energy and carbon reduction goals.

Budget and Schedule

III. Spending Summary by Budget Category

	Approved Budget (SF-424A)			Total	Actual Expenses		
Budget Categories per SF-424A	**BP 1**	**BP 2**	**BP 3**		**BP3: 17Q21**	**Cumulative**	**%**
a. Personnel	$86,422	$72,508	$96,189	$255,119	$2,073	$173,898	68%
b. Fringe Benefits							
c. Travel	$17,615	$33,974	$37,428	$89,017	$0	$17,337	19%
d. Equipment							
e. Supplies							
f. Contractual	$748,706	$880,047	$227,279	$1,856,032	$1,149	$1,685,806	91%
g. Construction							
h. Other	$30,100	$40,100	$100	$70,300	$0	$9,809	14%
i. Total Direct Charges (4)	**$882,843**	**$1,026,629**	**$360,996**	**$2,270,468**	**$3,222**	**$1,886,850**	**83%**
j. Indirect Charges	$83,484	$72,508	$102,002	$257,994	$2,342	$175,782	68%
k. Total Charges (5)	**$966,327**	**$1,099,137**	**$462,998**	**$2,528,462**	**$5,564**	**$2,062,632**	82%
DOE Share	$ 772,784	$ 878,774	$371,629	$2,023,187	$4,415	$1,648,973	82%
Cost Share	193,543	220,363	$91,370	$505,276	$1,149	$413,659	82%
Cost Share Percentage (6)	20.0%	20.0%	19.7%	20%	20.7%	20.1%	100%

Schedule		
Budget Period 1: 1Q17 - 4Q17	Start: 1/1/2017	End: 12/31/2017
Budget Period 2: 5Q18 - 8Q18	Start: 1/1/2018	End: 12/31/2018
Budget Period 3: 9Q19 - 12Q19	Start: 1/1/2019	End: 12/31/2019
Budget Period 3: Extension 13Q20 - 17Q21	Start: 1/1/2020	End: 3/31/21

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