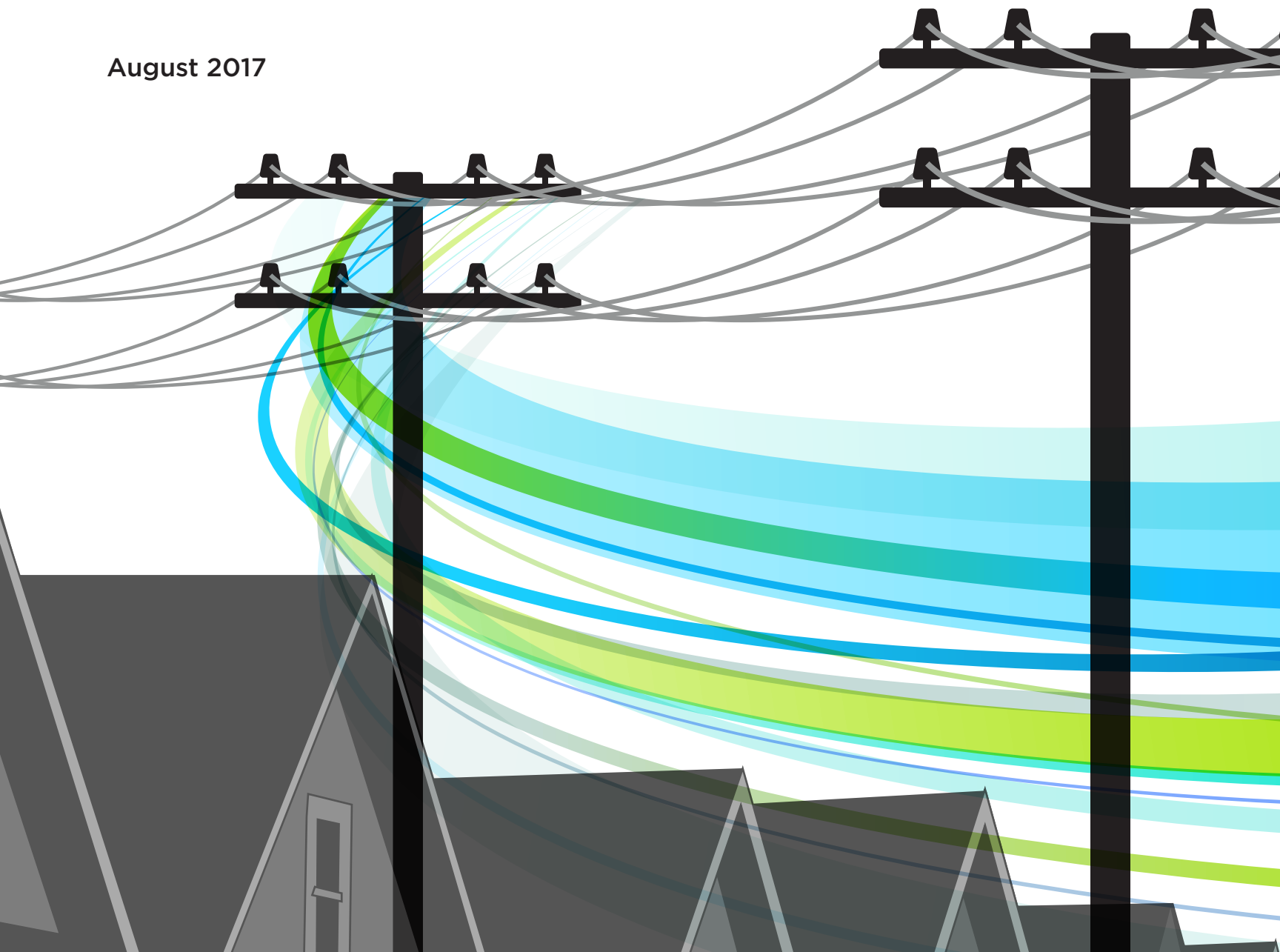


VOICES of Experience

Integrating Intermittent Resources.
What Utilities are Learning.

August 2017



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Introduction

Integrating high penetrations of intermittent resources into electric systems is a bit like preparing for a hurricane. Utilities know this transition is coming, so they are preparing their systems to mitigate the potential impacts and watching the weather forecasts.

From Hawaii to New York utilities are preparing their systems for a growing penetration of customer-sited generation. They are testing and adopting new technology designed to provide better visibility and control; collecting and interpreting the increasing amounts of data needed to plan, forecast, and model their future systems; and focusing on their customers—listening and responding like never before—plus streamlining their processes to enable faster interconnections with more transparency. Because no matter where they are now, utilities know that in the future, they will be **operating differently**.

Realizing the benefits of bringing utilities together to share their experiences, the Department of Energy's Office of Energy Delivery and Electricity Reliability assembled a working group of utility representatives to collect the experiences, insights, and lessons learned from integrating intermittent resources on the distribution grid. (More information on the working group is included in Appendix A.) The working group participated in a series of topic-based discussions and regional meetings where the utilities at the forefront of this transition provided valuable insight into the challenges, solutions, and lessons learned from integrating variable generation. The purpose of the **Voices of Experience | Integrating Intermittent Resources** is to share that knowledge with the industry to enable utilities to better prepare for the operational challenges they face.

One of the initial insights from this project is that utilities large and small—and from across the country—are interested in this topic. Even those with very little customer-sited generation recognized that these resources will be a growing part of their generation mix going forward, whether because of state policies or growing customer interest. These utilities wanted to be proactive by discussing challenges and successes, and learning from others so they could prepare for the future. And the main message from the utilities on the leading edge: **Start preparing now.**



Start Preparing Now

The main message from utilities on the leading edge of integrating intermittent resources to those with low penetration levels is to start preparing now. Here is their best advice on preparing for more customer-sited generation.

Expect exponential growth.

Utilities reported that penetration growth rates may follow more of an exponential, viral growth rate rather than a steady, straight line. In a recent study, Tendril analyzed data sets in the San Jose region and found that neighbor influence and peer pressure were significant drivers of solar adoption. In analyzing data from 2005 through 2015, Tendril found that the first nearby solar neighbor increases a person's likelihood to go solar within the next year by nearly threefold; the second neighbor makes that a sixfold increase.¹ So even if your growth rate is slow and steady now, you could quickly become inundated with interconnection requests.

¹<https://www.tendrilinc.com/blog/rooftop-solar-spreading>

Capture your load profiles.

High penetrations of intermittent resources such as customer-sited rooftop solar can have a significant impact on load shapes. Utilities will need detailed data about their systems and customer energy usage to develop models and perform hosting capacity studies that will allow them to integrate higher penetrations of intermittent resources, and public utilities commission may want to see real-time, historical data. Collecting and managing this new data may require new processes, skills and resources, funding and most importantly, time.

Develop your tools.

Grids are now dynamic and require integrated models that enable operators to look beyond one section at a time. You will need a model of your primary system that includes equipment characteristics such as phasing, line impedance, generator characteristics, the location of the distributed resources on your system, and even inverter information. This data may not be readily available and its collection should be integrated into your business processes early.

About this Guide

The information in this guide came directly from the people in the industry who are working the challenges—the ones who are interconnecting the new resources, testing emerging technology, and analyzing the data while continuing to keep their grids operating safely and reliably.

This guide started with a kickoff meeting at San Diego Gas & Electric (SDG&E), followed by a series of conference calls about specific aspects of integrating intermittent resources, interviews with individuals at utilities, and a number of onsite meetings at utilities such as Pepco, Vermont Electric Power Company (VELCO), and Salt River Project (SRP). (More information about the working group is provided in Appendix A.)

While the effort started with 14 individuals at a handful of utilities in states on the leading edge of this topic, the working group—those that participated in the discussions—grew to more than 90 people representing more than 30 utilities and organizations. Wherever possible, this guide preserves the voices of the participants that came through the many peer-to-peer discussions. However, the themes and common ideas that emerged have been summarized and edited into a single insight or experience without attribution to any one person or organization.

Utilities that have been interconnecting intermittent resources have learned lessons and gained insights along the way—sometimes the hard way—that can be applied to other utilities who may be experiencing similar challenges or are interested in preparing for operating in the future with much higher penetration of intermittent resources. The goal of this guide is to provide information that might not be accessible elsewhere—the kind you might get from talking to a colleague at a neighboring utility. A few things to note:

- All utilities are different and have unique systems and requirements. This document is not a road map that must be followed. It is a compilation of advice and insights that other utilities have learned through their own experience integrating intermittent resources.
- Much of the advice and insights (What Utilities are Learning) are not attributed to a single source because they are summaries from group discussions. Examples (What Utilities are Doing) from specific utilities are included with permission from the source of the information.
- Along the way, the working group identified a number of resources that might be helpful, including a number of documents produced by the Electric Power Research Institute (EPRI) and the national labs. The lists provided are not intended to be comprehensive, but rather offer additional information that might be useful.

And finally, this guide is not a how-to manual or technical report that must be read from cover to cover. It is simply meant to share what utilities are learning about the challenges of integrating intermittent resources and what they are doing to meet those challenges.

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Key Insights and Takeaways

The focus of this effort is to document what utilities are doing to overcome some of the engineering and operational challenges of integrating intermittent resources in the distribution grid. These six key themes emerged from the many peer-to-peer discussions and meetings:

1. Customer engagement has new import.

Many utilities are seeing an increase in customers interested in “greening” the energy supply. These customers require—and expect—a new level of information and engagement from their utility. They want responsive, informed customer service professionals who take the time to answer their questions. They are used to having services and information at their fingertips (think Amazon and smartphones), and they often request detailed data beyond the utilities current capabilities. They expect the utility to operate with speed and agility—especially when processing their interconnection applications.

2. Engineers (and others) are working the challenges.

Both the design and operation of the grid are changing. Understanding these changes and developing staff, capabilities, tools, and processes to operate safely and reliably in this new environment takes time. Learning how to operate with high penetrations of distributed, intermittent resources requires testing new technology, determining the value of these resources, and understanding the impact on the existing systems.

3. Policy and societal preferences are ahead of technology.

Penetration rates are often catalyzed by policies designed to support renewable energy goals. Utilities and researchers are just beginning to understand what is necessary to operate safely and reliably with variable resources and to develop the data, tools, and technology they will need to do so—such as precise hourly weather data, sophisticated models, advanced inverters, and other devices to round out their toolkit. And it is important to consider the nascent nature of some of the the technology.





4. Visibility, predictability, and control are key.

When penetrations of customer-owned systems are low, the fact that utilities do not have visibility of the customer's system is less of an issue. But as penetrations grow, the ability to see, control, and predict the output from distributed resources, and the aggregate behavior at the distribution circuit level becomes increasingly important. Computer models of a system will tell operators what they should see, but without monitoring, utilities will not be able to see the actual impacts on system performance. Advanced automation and supporting systems enable operators to ensure safety and reliability while facilitating increased integration of distributed energy resources.

5. Each situation is unique.

All distribution systems were “custom built” over time in response to changing populations and demand, giving each system unique characteristics that determine the utility's approach to connecting intermittent resources. Different regulatory environments and populations may also require different approaches to integrating customer-owned systems, and there are costs, legacy systems, and infrastructure to consider as well. There is no single solution or formula for utilities to follow; each utility must determine their own best approach.

6. Collaboration is essential.

Adding customer-sited resources to a utility's generation mix adds new complexity—both internally and externally. Planning for the future requires a holistic view: one where the utility must not only understand its own resources and plans, but also, those of its customers, regulators, and the developers in its service territory. While it can be challenging, collaboration and open, ongoing communications will help everyone understand the constraints and requirements for safely connecting these new resources to the grid.

Note: Even though the peer-to-peer discussions often included the implications of policy and economics, this guide does not attempt to explore the cause and effect between policy and related technological challenges.

Operating Differently

Intermittent resources are turning grid operations upside down. Instead of seeing voltage decrease along the length of the circuit, engineers see a rise in voltage where intermittent resources are connected. Instead of thinking about load curtailment on peak days, engineers and operators are now thinking about capacity curtailment from high solar output during times of low load. Not only do utilities need to think differently, they need to operate differently.

Location, Size, and Ownership

Whether the intermittent resource is utility-owned and sited or customer-owned matters to utility operators because the size and location of the system can affect grid operations.

- Customer-owned resources can limit the utility's options for reconfiguring the grid to deal with system disturbances or reliability issues. Reconfigurations can be difficult with high levels of intermittent resources, especially in densely populated areas.
- Utility-owned systems can be sited and sized to meet operational needs. For example, oversizing the photovoltaic (PV) system or changing the power factor (to provide VAR support) can help to accommodate dips in output more easily.
- Adding small-scale intermittent generation in densely populated urban areas where there is more load can be easier than adding it in rural areas where there could be equipment constraints or it could create excess generation.
- In rural areas, there is typically lower load but more land for customers to oversize their systems, making these lines more apt to experience disruptions and require upgrades.

What are utility operators' concerns?

- Effective grounding during high-side faults
- Reverse power flow and its impact on the substation or transmission system
- Reduced spinning reserve, which can cause frequency issues
- Need for situational awareness
- Changes to load and generation balancing
- Impact to distribution automation schemes and line regulation regarding thermal equipment rating
- Phase balance
- Distribution management system (DMS) information requirement for PV and storage systems to determine contingency or automated switching schemes

Visibility and Control

Operators need to know what resources are connected to their systems and where those resources are located to operate the grid effectively. Utilities and vendors are working on solutions that will give utilities more visibility and allow for better control.

- Utilities need feeder visibility. Utilities need to see the voltages to understand the impact of intermittent resources on the system. System models will tell utilities what they should see, but it isn't necessarily what they will see.
- Having solar data from customer-owned generation are important for understanding the actual production from PV systems. This information can help with planning and when restoring the system after a disturbance.
- To restore power after a disruption, utilities will have to accommodate load that was previously being supplied by customer-owned systems (which trip offline during an outage) until those systems can come back online.
- Utilities need secure, low-cost, robust communication and control for operating the grid with intermittent resources.
- Utilities with advanced distribution management systems (ADMS) or utilities that have mapped intermittent resources into their system are better prepared to understand the impact of the resources on system performance data. However, they may not have the control they need to mitigate the issues.

Operation, Maintenance, and System Upgrades

Operating and maintenance costs may be affected by the addition of customer-sited resources, and system upgrades are often needed even when non-wire solutions are employed.

- Traditional load-shed schedules may need to change when new customer resources are added to a system, and determining the exact load shed amount for under-frequency events becomes more difficult. Protection schemes may also need to change with higher penetrations of PV and can become complex.
- Standards, including protection standards, need to be updated faster to reflect current conditions.
- The variability from PV systems may cause greater wear on transformers' load-tap changers and load regulators, creating shorter maintenance and replacement cycles. This will have an impact on the utility's operating and maintenance costs (potentially increasing them).
- Voltage regulator controllers and load-tap changer controllers are typically unidirectional. With intermittent resources, these devices will need bidirectional capability and protection upgrades.
- Upgrading protection relaying or reclosers could cause coordination issues.
- Low-voltage primary systems such as 4 kilovolts (kV), which were often installed when demands were lower, have less capacity for hosting intermittent resources. For utilities anticipating higher penetrations of PV on their system in the future, it might be worth phasing out these systems and going to higher voltage options.
- Oversizing system components (such as conductor size) can enable higher penetrations of intermittent resources in the future, but must be weighed against cost and other factors.
- Non-wire solutions* are an option in some circumstances, but they do not fix aging infrastructure issues.

*Non-wire solutions are system investments and operating practices that can defer or replace the need for specific infrastructure investments (e.g., replacing wires, poles, and other electrical equipment or building new substations).



Generation Mix

The characteristics of the resources—e.g., fuel source, size, capacity, ramp rate, cost, contract type—in a utility’s generation mix determine how the grid is operated and the solutions a utility will be able to employ to address intermittency.

- Current grid designs require some amount of spinning reserve or other forms of inertia to firm grid operations and limit reliability issues. Without sufficient inertia, the system will recover from frequency events more slowly than previously experienced, which could cause the system to collapse. With large amounts of intermittent resources (as a percentage of overall generation), a grid-level disturbance could cause a cascading event as the intermittent resources begin to trip off line if there is no traditional generation to back it up.
- The flexibility of the utility’s other generation sources can affect the utility’s ability to manage intermittency. A utility with more rigid or “inflexible” base-load generation (such as contracts for minimum generation, or resources with slow ramp rates) can make it difficult for the utility to respond to changes in the intermittent resource. And depending on a utility’s generation mix, high penetrations of PV may require additional quick-start units.
- Because energy efficiency measures change feeder characteristics and the impact of variable resources are highly dependent on the characteristics of the feeder, new efficiency measures might cause issues on a feeder where previously there was none.

What factors determine the impact of intermittent resources?

- Location on the circuit—near substation versus end of circuit
- Circuit rating—4 kV versus 12 kV
- Urban versus rural circuit
- Circuit minimum loading
- High versus low circuit X/R ratio (reactance to resistance ratio) at location
- Aggregate distributed generation capacity
- Voltage regulation equipment

Additional Resources

[Impact of Low Rotational Inertia on Power System Stability and Operation](#)

A white paper that investigates the impact of low rotational inertia on power system stability and operation, contributes new analysis insights and offers mitigation options for low inertia impacts.

[California ISO: Frequency Response Phase 2](#)

An issue paper that describes market design limitations identified with the independent systems operator’s (ISO’s) ability to (1) position its fleet to provide sufficient primary frequency response that maintains grid reliability during the largest contingency events and (2) incentivize and compensate resources for frequency response capability and provision.

Advice on modeling your system

- Start building your distribution system model now, including equipment characteristics. You will need a model of the primary system to test out your theories.
- Build the gathering of data and mapping of resources on the system into your business processes early.
- Grids are now dynamic and require integrated models that enable operators to look beyond just one section at a time.
- Equipment models are important, but difficult to develop because the data needed such as phasing, line impedance, generator characteristics, and even inverter information are not readily available.
- Mapping the location of all distributed energy resources (DERs) on your system is imperative. Without this information, it is difficult to analyze what is happening on the system and fully understand the impact of new resources.

Streamlining Interconnections

More than just a technical screening, the interconnection process is also a unique opportunity for utilities to build relationships with their solar customers and the installers working in their service territories.

The interconnection process is seemingly straightforward: the customer or installer provides the technical specifications about the planned system and the utility evaluates the impacts to the grid and then either approves the application or communicates any necessary upgrades. However, it isn't always simple. Obtaining the necessary information and keeping all parties up to date on the application status can be challenging—especially for utilities with large numbers of applications or a sudden increase in interconnection requests.

The “time to connect”—the total time from when a customer submits a request to interconnect to a utility’s distribution grid to when it is operational—is an important interconnection metric. But there are many

variables in this process that are beyond the utility’s control. Deadlines (or timelines) for interconnection approval vary by state and are often determined by local utility commissions or boards. In addition, interconnected systems will likely have to adhere to local codes, pull permits, and pass inspections from Authorities Having Jurisdiction (AHJs) such as a municipality or even homeowner associations. Having a transparent process that customers and installers can easily follow is very important to overall customer satisfaction.

When the number of applications is small, utilities have been successful at managing the process manually through email and phone calls between the customer and a dedicated customer service representative. However, utilities with high application volumes for

customer-owned rooftop PV systems are finding that tools such as web portals are necessary for managing the interconnection process and keeping customers (and the project installer or developer) informed. The functionality of these web portals ranges from simply providing an online method for the customer to provide data or submit an electronic copy of their application to fully integrated online tools that help utilities track the application status and manage internal workflows. A web portal can also help utilities process a larger volume of applications without needing a corresponding increase in customer service staff by automating some of the approvals and helping reduce human errors in the process.



Biggest Challenge:
Processing customer applications in a timely manner in order to meet customer needs while ensuring system reliability and safety.



Communicating the need for system upgrades

Often the process for communicating application approvals to customers is mandated by the state's public utilities commission (PUC) and it varies by state. Some utilities never deny a request to interconnect, but will approve them with conditions. For example, the approval may include a description of a required system upgrade that the customer must pay for or instructions for "right sizing" the system. Communicating to a customer that their interconnection will require a system upgrade that will be an additional cost can be challenging. Below are three of the ways utilities are handling this somewhat sensitive situation.

1. Working with developers.

Communicating with developers if upgrades are required in a given area allows the developer to cluster the applications and spread the upgrade costs among multiple customers.

2. Upfront in the application.

One option is to include this information in the interconnection study results with the technical requirements and cost estimates. Another option is a notice in the interconnection application stating that customers with systems that cause high voltage or overloads to the transformer will be responsible for the cost of the required system upgrades.

3. In a letter to the customer.

This allows utilities to explain, in as simple terms as possible, what the constraint on the system is and the upgrade that is needed. When the expense and requirements are clear, the customer can decide to upgrade or not. This may incentivize a customer to downsize their system somewhat so it can be connected without upgrades.



What utilities are learning

Transparency is key. Keep customers and contractors informed throughout the application process with letters or emails that tell them when key milestones have been met, such as approval to install, meter exchange, and authorization to operate.

Two levels of review may not be enough. Utilities with two review levels (simple and full impact) found that with increasing penetrations they need to add another supplemental review to address small issues that are not big enough to require a full review.

An online system can save money. Customer interest in self-generation might start slow, but it is likely to grow—often exponentially—even in states with low electricity rates. Once applications become significant, a manual process will require additional resources and could create backlogs or delays. Although the upfront costs for developing an automated application process can be significant, it will save money down the road.

It's not too soon to start. The decision to move to an online or automated interconnection process is usually driven by the growth in interconnection requests. When you see policies that are driving growth of customer-owned generation in your service territory, it is time to start developing an automated online process because it will likely take a year to get a system operational.

It's best to have your data in a single system. Many states require extensive reporting, and manually accessing data from several systems can be challenging and time consuming. Once your online system is operational, you will need time to enter all the applications that were approved manually prior to the new system so that the data in your GIS are accurate. Depending on how many applications were approved, this could be a time-consuming task.

Think of your application system as a planning tool. Think through business processes upfront and how they will be handled, including noncompliant customers who have installed a system but don't have an approved interconnection application.

Make the installers allies. Work with contractors in your area to help them understand the interconnection application process and system constraints. Some utilities are able to get information from contractors about customers who have withdrawn or decided not to move forward with an application, which helps decrease the number of expired applications in the system.

Collaborate with AHJs. Utilities can have a number of authorities having jurisdiction (AHJs) inspecting customer systems with differing levels of expertise and timeframes, affecting the time to connect. Work collaboratively with AHJs to help them understand the process, technology, and system requirements. Some utilities have found that an online application process helps streamline approvals from AHJs by allowing them to approve and demonstrate approvals online.

Insights and advice for developing an online application process

Consider a custom tool. Utilities with high application volumes for rooftop solar systems are choosing custom portals even if they originally implemented an off-the-shelf solution. Custom solutions are usually needed to create an application processing system that integrates with other utility systems like GIS or CIS and has the capability to manage workflow and generate status reports, customer letters, and other automated features.

Know how it works. Make sure you understand the functionality of your software and how much manual intervention will be required. Do not assume that your process will be automated just because it's online. Some systems may require manual processing on the back end.

Reduce errors with menus. Application errors and incomplete applications can cause delays and increase processing costs for utilities. Online systems that are designed with pull-down menus and other predefined fields help reduce these issues. Some utility portals won't allow the application to be submitted without all fields complete and necessary diagrams or paperwork uploaded.

Try before you buy. Look at all systems that are available to determine which ones will best meet your needs, and then try them out before making a final decision. Most vendors can set up a demonstration site for you.

Engage users and contractors in the design process. Consider at least one focus group with customers during development. Better yet, perform one focus group midway through tool development and another one prior to going live to gather feedback.

Ensure your system can route applications efficiently. Your automated system should be designed to flag installations that will raise issues and let the others pass through the approval process quickly, especially as volume levels rise.

Include a payment system. If there are fees involved with your application process, consider including fee payment in your system. Speedpay® is one service that utilities have used that can provide online invoicing and receive electronic payment. This will help reduce manpower and application processing time because you won't have to match checks with submitted applications.

Accommodate revisions and updates. Make sure your automated system can accommodate application revisions made by the contractor. For example, if the customer decides to change the system size from what was approved—which happens quite often—make sure the online system will allow the contractor to easily revise the application instead of having to start over. In addition, tariffs and timeline requirements can change, so your system needs to be able to easily adapt to these.

Track approval times accurately. One utility is making sure to include functionality that will allow it to put the time to approve on hold when the project is put on hold. This makes it possible to accurately track the approval timeline.

Include time to develop automated messages. Considering and writing the automated messages that your customers will receive from the online portal takes time. Make sure you budget the time and cost of developing these important messages.

Don't forget about community solar. Consider incorporating future community solar projects (with multiple system users) into the initial portal design. This will help with regulatory reporting.

Develop an outreach plan. You will need to let your customers, installers, and developers know your online tool is available and encourage them to use it. Your communication plan should drive traffic to the tool, provide information on how to use it, and highlight the benefits to the users of submitting their applications online.



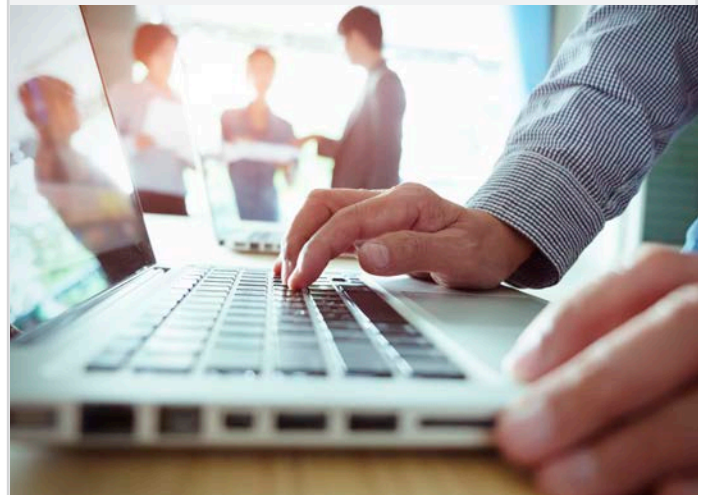
10 things to consider for your online portal

1. Allow for decimal points in the system sizing field.
2. Include the capability to upload documents, diagrams, and photos.
3. Include online payment and signature options.
4. Integrate with other systems such as GIS and CIS.
5. Incorporate pull-down menus to reduce input errors.
6. Include a community solar project option.
7. Ensure the system is able to flag installations that might cause issues.
8. Allow for application modifications to address changing requirements.
9. Give customers the ability to click on a location map to get feeder information.
10. Allow contractors to designate access to multiple users and see aggregated reports for all pending applications.

Top 5 benefits of online systems

These are some of the benefits mentioned in the working group discussions:

- Improves the quality, speed, and effectiveness of the application process
- Decreases the number of errors and incomplete applications
- Provides immediate application status updates
- Streamlines the workflow processes and internal communications
- Reduces costs associated with labor hours, miles driven, and postage.



What utilities are doing



Westar Energy—Starting Small

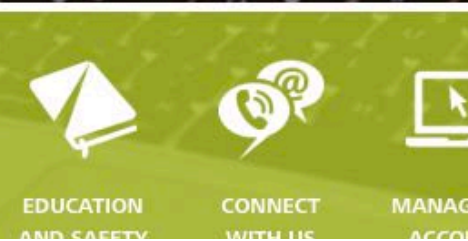
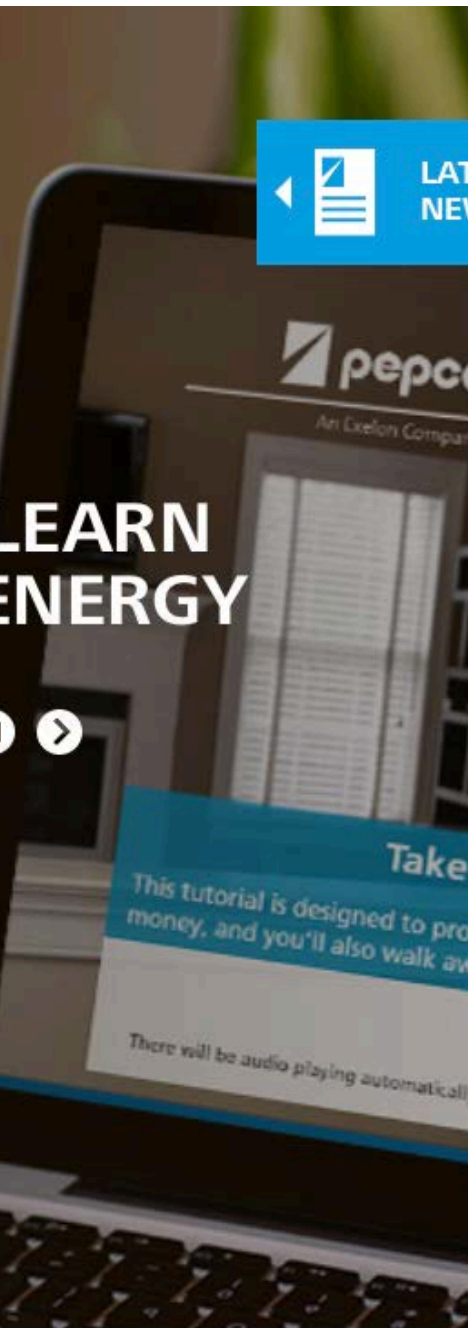
Westar Energy is an investor-owned electric utility headquartered in Topeka, Kansas, serving nearly 700,000 customers. In 2010, Westar received only 20 requests to interconnect customer-owned rooftop solar systems; however, it expected that number to grow and wanted to be prepared. So, Westar began planning for an online system that would streamline its process and enable it to handle a larger volume of requests in the future.

The first hurdle for Westar's team was convincing its management to fund the development of an automated process when requests for interconnection were few and manageable. Westar initially considered an off-the-shelf product, but in the end decided to develop a custom tool in-house that enables both online access for its customers and better workflow management for Westar's customer services and engineering departments. The tool is a PDF file for the application, connected to an internal SharePoint site. The tool requires all data fields to be complete, and a one-line diagram uploaded, to complete the submission. The development of its tool took the better part of a year, but Westar is glad it planned ahead. In 2016, interconnection requests grew to 500 and the online tool has allowed it to process and manage applications more efficiently than the manual process would have.

Westar learned many lessons along the way that it shared with the working group. Here are a few:

- Ask for system size in both AC and DC.
- Include the distance from the installation to the disconnect switch in your form.
- Allow for decimal points in the system-size field.
- Indicate whether the system is owned or leased and whether the facility is commercial or residential.
- Allow for online payment of applications.
- Think through the entire process to ensure the portal accounts for all scenarios. Examples of scenarios that could be overlooked include the transfer of ownership from the contractor to homeowner for new construction and the sale of an existing property to a new owner.
- Ask the applicant to indicate if it is a construction meter or service meter.

Advice from Westar: Start planning now. Even if you are a small utility with relatively few requests for interconnection, start developing a robust online portal and gathering data for your models.



Pepco—Integrating Work Management

With roughly 2,000 requests for interconnection per month, Pepco launched its online application portal in March, 2016. The planning for the portal started back in 2012 when Pepco noticed not only a sharp increase in the volume of calls coming into their customer service center, but also, that its customer service representatives were spending more time helping customers understand the interconnection application process and tracking down missing information. That's when Pepco decided to develop an online portal to allow its customers to input their application information and help Pepco manage the workflow, data tracking, and regulatory reporting.

Pepco started the portal development by simplifying its interconnection application process into two steps and reorganizing its staff around the two steps. One team is focused on helping the customer and contractor from the time the application is received through approval to install; the other team works with the customer from the time the system is built through the authorization to operate.

Here are the basic components of each step:

Step 1: Application for permission to build

1. Customers enter the application information, sign, and submit the application. If a contractor completes the application information, it must first be signed by the customer before submitting. Pepco doesn't see the application in their system until the customer signs it.
2. After the application is submitted and reviewed for completeness, an automatic email is triggered and sent to the customer and/or contractor acknowledging receipt. Engineering is also notified that there is an application to review.
3. Three separate engineering groups are tasked with reviewing the application to evaluate different aspects of the system and to verify that the solar installation will have no adverse impacts on the grid. Pepco has now implemented a fast-tracking application process through which modeling tools now allow for one centralized engineering group to review all applications, thus expediting the approval process.
4. Once the engineering review is complete and signed off, an email is sent to the account coordinators to say the application has finished engineering review and explaining what needs to be done for approval (e.g., if a transformer upgrade is required) or if the application is approved. Over 95% of the applications are approved as submitted.
5. An email is sent to the customer and/or contractor saying they have approval to install the system and instructing them to submit the required documentation for approval to operate their system.

Step 2: From permission to build to permission to operate

1. Once the system is built, the customer or contractor submits the required documentation for part two of the application process.
2. Pepco completes a task that automatically sends notifications to the meter department to exchange the meter and the billing department to start the coding process to code the customers as NEM (Net Energy Metering). If an account is not coded as NEM and Pepco sees reverse rotation on the meters, the system generates an alert of meter tampering.
3. Once the meter is exchanged, there is another system that is tied into the work management system that notifies the customer or contractor that the exchange has been completed. This authorizes the account manager to send the customer notification that they have permission to operate, and an email is automatically sent to the customer thanking them for choosing to go solar and informing them that they can operate their system.

The portal has provided numerous customer benefits and fostered better internal communications between Pepco's engineering, billing, and metering departments. Pepco's next step is developing an automated approval process that will run applications through the power flow analysis to ensure that no applications are approved that could result in negative system impacts for other customers.

Benefits of Pepco's online application portal

- Improves the quality, speed, and effectiveness of the NEM application process
- Intuitive and interactive application process guides customers step-by-step
- Many pull-down lists and field validations for easy input
- Provides data validation, reducing application errors and missing information
- Allows customers to monitor their application's status in near real-time through a personalized dashboard
- New online contractor account includes the ability to designate access to multiple users
- Accessible from any internet connection, including tablets in the field
- Quickly moves the application to the next step in the process
- Ability to see aggregated reports for all pending applications submitted online by contractor
- Online signature feature eliminates the need for physical signatures
- Upload attachments online—no need to email or mail supporting documents
- Saves paper and postage from printing and mailing hardcopy applications
- Provides immediate updates on missing or inaccurate information



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Southern California Edison—Achieving Faster Approvals

Southern California Edison (SCE) receives around 4,000–5,000 applications per month and has experienced this volume of requests for interconnection for several years. In 2014, SCE realized it would not be possible to sustain that volume with the manual processes that it was using. It was commonly taking 50 or more days to get an application approved, which was not meeting customers’—or the company’s—expectations. Today, SCE’s automated, online process enables 54% of its applications to be processed and approved to operate in one day.

Developing SCE’s automated process started by creating a cross-functional team from multiple departments such as metering, engineering, and interconnection to determine where processes could be streamlined. Using knowledge gained from past applications, SCE created nine “screens” to determine when a project needed further engineering study. The screens included things like the number of other solar customers on that transformer, if it is an atypical interconnection, and if the system connects to the line tie or the breaker. If an application fails one of the screens, then it is sent to engineering. The screens have significantly reduced approval times for the majority of projects that don’t need further engineering review.

The company’s goal was to create a one-touch-point system where the application comes in, one person gets it, one person analyzes and processes it, and all the documentation (i.e., metering, contracts, engineering, etc.) is done through the tool without requiring additional emails or external processes. Although SCE purchased an off-the-shelf software package, it took about a year to go from conception to an operational tool. The implementation included hosting focus groups prior to going live and promoting the tool through workshops and other communications.

Looking to the future, SCE is developing a more robust tool that can be extended to every project (the current tool processes only NEM applications). The new tool will be a stronger, higher functioning platform that integrates the interconnection process with planning, operations, and even contracts and regulatory requirements. Development of that tool is in the initial planning stages and will take several years to complete.

SDG&E—Cutting Costs

SDG&E's decision to develop an online portal was driven by the incremental growth in requests for interconnection and the increase in staffing needed to keep up. In 2000, SDG&E processed about 3,000 applications. By 2015, the number had grown to 27,000. With no off-the-shelf solution available, SDG&E developed its online portal in-house with the goal of providing a better way to communicate with its solar customers and more milestone transparency.

SDG&E's portal incorporates many innovative features, including:

- Real-time status modifications and updates
- Inspector workflow tracking
- Fast-track management
- Extendable, scalable architecture
- Map installations into SDG&E's GIS
- Integrated reporting functions
- Photo upload functionality to enable virtual inspections and approvals.

Coupled with SDG&E's advanced metering infrastructure, which allows for remote programming to handle reverse power flows, the company's portal has contributed to millions of dollars in reduced labor hours and miles driven. SDG&E's future plans include linking the system to hosting capacity and load-flow analysis.



Massachusetts Utilities—Standardizing the Interconnection Process

The Massachusetts Department of Public Utilities (DPU) has established a [Technical Standards Review Group](#) (TSRG) to tackle technical issues related to connecting intermittent resources. The group is composed of seven members—one member from each of the state’s four utilities, and three non-utility members. Someone from the DPU is a permanent member of the group. Besides tackling technical concerns, the TSRG developed the Common Technical Standards Manual, which highlights the commonalities and differences among the public utilities’ interconnection processes. The TSRG bylaws, which specify that another member cannot criticize or require changes to another utility’s processes, have fostered collaboration within the group. The TSRG has helped to increase transparency, improve communication, and provide utilities and developers with a better understanding of each other’s concerns and requirements.

Topics of discussion have included:

- Distribution feeder hosting capacity
- Substation transformer back-feed
- IEEE 1547
- Supplemental review for voltage-and power-quality safety and reliability
- Review of two NREL reports: [Inverter Ground Fault Overvoltage Testing](#) and [Inverter Load Witness Test Protocols](#)
- Penetration screening of the supplemental review
- Network interconnections on both the primary and secondary.

Helping Customers Understand the Interconnection Process

The interconnection application process can be complicated for customers, and utilities are working to provide clear information on the steps necessary to submit the interconnection application and receive approval. This helps to alleviate frustration and to address customer questions upfront. Below are examples of resources that utilities have developed to communicate the interconnection process to their customers.

SCE

[The Interconnection Handbook](#)

This document identifies the technical requirements for connecting new facilities to the SCE's transmission system.

Kaua'i Island Utility Cooperative (KIUC)

[KIUC Interconnection Process](#)

KIUC has a manual interconnection application process that requires the system owner to complete a paper form and mail it or hand deliver it to the utility.

SDG&E

[Net Energy Metering Online Application](#)

[User's Guide -- Contractor](#)

SDG&E has a NEM Online application User's Guide that walks contractors and customers step by step through the online process with screen shots of each step.

Arizona Public Service Company (APS)

[Interconnection Requirements for Distributed Generation](#)

APS provides a manual that specifies the minimum requirements for safe and effective operation of any distributed generation electrically interconnected with the APS radial distribution system (21 kV or less).

Pepco District of Columbia

[Interconnection Application Process Steps](#)

Pepco provides a one-page graphic to illustrate the application process.

Westar Energy

[Interconnection Process Flow Chart](#)

Westar Energy provides a flow chart on their website to illustrate the interconnection process for their customers.

National Grid

[Interconnection Process](#)

National Grid provides a step-by-step outline of their interconnection process with links to the required forms.

Planning and Forecasting

Distribution planning used to be a straightforward process that focused on asset and infrastructure maintenance, evaluated demand forecasts using predictable load shapes, and assumed the utility would supply all of the power to their customers. But the growth of customer-owned distributed energy resources has added a new level of complexity—and uncertainty.

All this is changing the distribution planning process, and utilities are starting to take a closer, more nuanced look at their distribution systems. Planners must now consider a number of new variables such as the locational benefits and costs of distributed generation, shifting peaks, energy efficiency, and demand response programs. New uncertainties abound: Where will DER be located? What will adoption rates be? How much can customer-owned generation be counted on to meet projected loads and potentially defer infrastructure investments? What new investments are needed to operate and optimize the system now and in the future? Utilities are just starting to think through how to incorporate these new variables into their analyses and determine what new tools they will need.

Having access and visibility into the size and location of customer generation is

increasingly important to system operators. Weather forecasting is becoming a significant component of planning as well. Previously, planners considered the possibility of major weather changes (e.g., an unusually warm or cold winter). However, with intermittent resources, utilities now need to determine the impacts that hourly weather changes—like moving cloud cover—have on customer generation, and ultimately on reliability.

New York, California, and several other states are on the leading edge of integrating distributed energy resources into their planning processes. These states are developing distribution resource plans that include the valuation of both demand-side and supply-side resources with the goal of evaluating both wire and non-wire solutions. The examples and insights included here are primarily from California, where investor-owned utilities have regulatory requirements

to file distribution resource plans. But utilities across the country are starting to think about how their planning and forecasting will need to evolve to meet the changing needs of their members and customers.

Growing Complexity

Smart grid technology gives more operational possibilities and customer-owned generation, which can be highly variable, creates unexpected load profiles, with generation flowing both to and from the utility. What used to be an analysis of the 1 in 10 adverse peak hour has transitioned to an 8760 quasi-dynamic load-flow analysis.

Biggest Challenge: Visibility into customer-owned systems and the amount, complexity, and granularity of the data needed for analysis.



What utilities are learning

- Distribution resource planning can be helpful to utilities in states that have robust clean-energy goals. It can provide an open, transparent process that produces data that regulators and stakeholders can use to meet grid modernization and clean-energy goals.
- One of the benefits of DER planning is increased stakeholder involvement. The plan can help the community, customers, and developers understand how the system works, as well as help utilities understand the projects that developers may be planning.
- Consider a cross-functional team for distribution resource planning that includes not only distribution planning staff, but also, staff from resource planning, customer solutions, and emerging grid technology. A cross-functional approach can facilitate coordination and communication across groups within an organization, and it can help the utility take a more holistic view of the process.
- Getting accurate data is one of the major challenges with distribution planning, including filling in the data gaps, scrubbing the data, and performing analyses.
- It will be helpful for planners just starting the process to look at hourly forecasts rather than only peak times. Depending on the level of detail, planners may also need: phasing data, which can be important with two-way flow; solar resource data (such as tilt, azimuth, and shading issues); smart inverter characteristics; and weather and geospatial data.
- Net load profiles will not provide the visibility into what is really happening on a system at specific times of the day. Utilities just beginning to evaluate the impacts of DER should consider using advanced metering infrastructure (AMI) data for load forecasting. AMI data will provide granular geospatial circuit load profiles, which are more informative than extrapolating load profiles from circuit net load.
- In some jurisdictions, customers are not required to inform the utility if they remove their PV installation or if it's destroyed during a storm or other event. This can affect planning because utilities will assume the resource is still on their system.
- With growing levels of generation that depends on weather and other environmental conditions, utilities are investigating ways to incorporate weather forecasting into their analysis of projected load, even anticipating weather-based voltage regulation schemes in the future.
- Utilities generally manage customers as a statistical group (customer profile) in models. The characteristics of that statistical group are changing, and utilities are trying to figure out how to include this in the planning models.



What utilities are doing

California Distribution Resource Plans

While many states have regulatory proceedings in response to increasing penetrations of DERs, California has been out in front, especially in requiring its utilities to develop [distributed resource plans \(DRPs\)](#). In 2013, California passed [Assembly Bill 327](#), which required utilities to file DRP proposals by July 1, 2015. The California Public Utilities Commission (CPUC) then instituted [Public Utilities Code Section 769](#) that provided guidance for the structure of the DRPs, including that they will “identify optimal locations for the deployment of distributed resources.” The code defines “distributed energy resources” as “distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.” Each proposal is required to do the following:

- Evaluate locational benefits and costs of distributed resources located on the distribution system. The evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings that the distributed resources provide to the electric grid or customers.
- Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
- Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
- Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning, consistent with the goal of yielding net benefits to customers.
- Identify barriers to the deployment of distributed resources, including, but not limited to, safety standards related to technology or operation of the distribution circuit in a manner that ensures reliable service.

The DRPs filed by California’s investor-owned utilities provide more insight into how each utility is approaching planning and forecasting:

- [Liberty Utilities](#)
- [PacifiCorp](#)
- [Bear Valley Electric Service](#)
- [SDG&E](#)
- [SCE](#)
- [PG&E](#)



PG&E's Experience Implementing the California DRP Ruling

Although PG&E had included distributed resources in its planning process previously, the CPUC ruling required it to view distributed resources in a more detailed and dynamic way. PG&E is creating a more formal and transparent distribution planning process to ensure that innovative solutions are considered and broader stakeholder perspectives are reflected. Here are some of the insights PG&E shared about its planning process with the working group:

- **Develop specific locational data and forecasts.** This includes geospatial characteristics, energy efficiency, PV, storage, and weather forecasts for specific locations on your system. These data can be used to create more realistic solar output shapes in order to better understand the specific impact these distributed resources have on load profile, capacity and load forecasts, and system reliability.



- **Look at hourly forecasts.** Utilities need the ability—through tools and data—to better understand which resources are actually reducing system peak. One suggestion to better understand non-coincident peak forecasts is to look at hourly forecasts rather than just peak times. Doing this has been helpful in understanding the real impact that PV might have on the load forecast.
- **Develop hourly load profiles.** PG&E performed an hourly data analysis (in a DRP pilot) to better understand the full load profile and identify the hours of the day or months of the year where there might be an issue such as voltage violations or a thermal overload on a substation or a voltage regulator somewhere in their system. PG&E is working towards full utilization of hourly data analysis in both load forecasting and circuit modeling to evaluate both wire and non-wire solutions for its system.
- **Coordinate the Integrated Resource Plan and DRP processes.** PG&E created the Grid Integration and Innovation Team with people from several departments, including distribution planning, resource planning, customer solutions, microgrid solutions, and storage. This allows for a more holistic, integrated view of DER planning.

Insights from an Independent System Operator—ISO New England

- The six New England states are incentivizing renewables in a variety of ways, and the ISO is adjusting its short- and long-term load forecasts to account for these activities and changing resource mix.
- The ISO created the [Distributed Generation Forecast Working Group](#) as a regional forum for stakeholders to provide input into long-term forecasts of the effects of solar PV.
- ISO New England plans its system ten years into the future. Solar PV is growing rapidly, and the ISO is developing the tools it needs to predict solar PV's rate of growth and the effect it will have on an hourly basis on the region's loads.
- Solar PV is reducing demand on the grid during the day and is increasing the ramp of demand during the evening hours. The timing of peak energy usage is evolving, with solar reducing peak energy demand in the summer, but not in the winter.

Forecasting Data and Tools

One of the challenges of adding customer-owned generation is determining what level of generation the utility can “count on.” If a utility includes these resources in its forecast, but the resources are not actually available when needed, this can have an impact on resource adequacy requirements. Utilities with high penetrations of intermittent resources are learning how to use increasingly granular data—from meters, inverters, and weather forecasts—to better predict how these resources will impact load shapes. Following are a few examples from the utilities that participated in the working group.

Using hourly analysis to better understand load profiles.

PG&E has pilot projects underway that take a deep dive into the hourly analysis to better understand the full load profile. This helps to determine at what hours of the day there might be an issue (e.g., voltage violation, thermal overload). Looking at the hourly data, planners can determine if the issue occurs periodically or if it occurs throughout the year, and they can then evaluate different solutions. For example, if the issue only occurs for two hours for a couple days in a couple of months, maybe it can be tackled with a non-wire alternative.

In addition, PG&E is building into its tools the ability to more dynamically and accurately understand which resources are reducing system peak. One of the key areas has been to get more detailed information on their non-coincident peak forecast by looking at hourly forecasts rather than only peak times. The hourly analysis has helped PG&E better understand the real impacts of PV on their forecasts.

Developing new tools.

Recognizing the growing impact of more frequent, more severe weather events—and of the exponential growth in distributed, weather-dependent renewable generation—on day-to-day, core operations, **VELCO** looked for analytical tools to substantially improve weather forecasting and link these weather predictions to renewable generation forecasts to better ensure grid reliability. Not finding a tool that met its needs, **VELCO** spearheaded a collaborative effort with in-state and regional partners and IBM to develop the [Vermont Weather Analytics Center](#) (VWAC). The VWAC provided grid operator and planners the visibility they need into the installed capacity and location of utility- and commercial-scale, as well as behind-the-meter, renewable generation. VWAC also provides hyper-accurate forecasts of wind, solar, and demand. It allows Vermont utilities to determine grid capacity for additional solar from the transmission system down to the substation level, and demand analysis to the substation level.

Recognizing that other utilities could benefit from these breakthrough grid management tools, **VELCO** subsequently partnered with IBM and Boston Consulting Group to launch an energy software company call [Utopus Insights](#). The data analytics platform the company offers allows utilities to better forecast the output of renewable energy resources and predict the impact on the utilities’ load shapes. The tool that utilizes “hyper-local” weather forecasting system coupled with leading-edge analytics to provide best-in-world wind and solar energy forecasts is called “Hypercast.”

Using weather data.

SDG&E has a dedicated meteorology department and has built one of the largest utility weather networks in the United States. The network was initially built to assist with fire risk and has 170 weather stations that measure 51 vertical levels up to 6,000 feet. Sixty-three weather stations were retrofitted with pyranometers to measure incoming solar radiation and predict solar generation. Working with the University of California, San Diego, SDG&E's service territory has been divided into 14 climate zones and a solar potential index was developed for each. Each day, the meteorology department develops 48-hour forecasts that can feed into the DMS to support short-term power flow models and daily operations.

Using these weather data, SDG&E is investigating the possibility of developing weather-based voltage regulation schemes. Currently, SDG&E has about 110,000 rooftop installations—about 670 megawatts of rooftop solar—whose output could change depending on the weather forecast. The idea is that SDG&E would schedule various modes—clear day, cloudy day, and intermittent day—using smart inverters to operate the system. For example, on a clear, sunny day, SDG&E might decide to turn off specific capacitors altogether and set the power factor for the units at a particular value based on predicted weather and associated output.

PG&E also has a meteorology department that is currently performing a deep dive into weather data from a variety of sources to understand some of the impacts on load profiles. They have developed solar shapes that look at the different intermittencies and climate zones and created expected shapes based on these data rather than just considering a normal sunny-day profile. PG&E wants to understand from the general planning perspective, based on climate zones, where the solar generation shape might be reduced because of the specific conditions in that area.

PG&E has been using LoadSEER, a tool built by Integral Analytics, which includes some of the weather components taken from weather station and geospatial data. The meteorology department has been using the analytics they've built around irradiance and cloud cover, using satellite imagery data, and doing some verification with NREL's PVWatts® calculator, to determine if the tools that are available are consistent with the data.

Using inverter data to develop forecasts.

Access to customer generation information is important—and challenging—as utilities perform their planning studies. One challenge is determining exactly how much customers' systems generate and therefore decrease load. Although the interconnection application specifies the system size, specifics about the area where it was installed (e.g., is it near trees that shade it during peak times) can alter output.

To accurately account for the impact of distributed PV in planning, **Pepco** uses a system to “backcast” how much generation occurred on its system in the past using a historical irradiance service from Clean Power Research that is based on previous weather conditions (i.e., cloud cover, sun irradiance). The report of backcast levels provides planners with a good picture of generation, net load, and peak load for a feeder at peak conditions, and for the installed solar, the ratio of installed capacity to output at the peak hour for the feeder. Forecasting these levels is essential to planning distribution circuits correctly.

Pepco is also working with SolarRetina—a company that crowdsources actual PV data from customer-owned rooftop solar systems—to compare its backcast values to real customer inverter data. SolarRetina creates time-series data for user-specified PV systems that utilities can download for their planning and forecasting studies. Using SolarRetina's data from inverters, Pepco compares those to the backcast values to look at last year's numbers and compare them to the potential for the current year or next year. The actual data can also shed light on year-to-year differences in solar output. Pepco found that the irradiance model, used for backcasting on an annual average, produced a slightly higher output level than the actual systems were generating.

Additional Resources

DeMartini, Paul, “[More Than Smart: A Framework to Make this Distribution Grid More Open, Efficient and Resilient.](#)” Greentech Leadership Group

[California Energy Commission – Distributed Generation Integration Cost Study](#)

Understanding Hosting Capacity

In the past, utilities used a rule of thumb—the 15% threshold—to determine how much DER the grid could handle. However, with increasing penetrations of distributed resources, utilities are moving to hosting capacity studies for greater accuracy. These studies can evaluate one limiting criteria, such as voltage, or multiple factors such as thermal, protection, reliability, and safety.

Hosting capacity is the amount of distributed generation (nameplate capacity) that can be connected to a location on the grid, requiring minimal or no system upgrades, and without adversely impacting power quality, reliability or safe grid operations. It is location dependent, feeder specific, and varies by time.

Hosting capacity studies aren't necessarily complex, but they can be. Even the less complex studies require lengthy processing times and significant manpower to verify model inputs and the accuracy of the results. Given that hosting capacity is a "snapshot" in time, the challenge for many utilities becomes allocating the resources needed to keep their hosting capacity results accurate. For some utilities, the California Electric Rule 21 Fast Track screening can serve as a good "first pass" when minimal data are available or accessible.

Though these studies require an investment of time and resources, utilities are finding that they have broad benefits—from serving as a "first pass" planning assessment, to providing a clearer picture of the limits and weak points in their systems.

Uses for hosting capacity studies

- **Interconnection—streamline the interconnection process to approve customer applications more quickly.**
- **Planning—provide a stress test for the system.**
- **Policy—understand policy implications from a system perspective.**
- **Research and Development—help identify operating margins and areas that need further study.**
- **Communications—provide decision makers and customers with information about system constraints.**



Biggest Challenge:
Collecting, validating,
and processing the
large amounts of data needed
to perform hosting analyses at
increasingly granular levels.



What utilities are learning

- Hosting capacity information allows utilities to be proactive rather than reactive to growing demands for grid interconnections.
- When utilities have short feeders and high capacity, performing a hosting capacity analysis is less important.
- It can take years to develop a robust database that can be used to calculate hosting capacity. Start collecting and validating this information now.
- Ensuring the accuracy of the data is a necessary, albeit time-consuming, aspect of performing hosting-capacity studies.
- There is no one method for determining hosting capacity. It can vary depending on the amount of data and the desired application of the results.
- Even when using the same method, each utility will need to decide on the study criteria and the limits to use based on factors such as system design practices, protection schemes, and relay schemes. The categories, however, will likely be the same and include thermal overloads, voltage flicker, steady-state voltage, protection, and operational flexibility.
- For utilities with low penetrations, conducting a hosting capacity study for minimum load conditions should be sufficient and can be performed with monitoring that most utilities already have in place.
- The most critical part is to have the existing model, the impedance model of the feeder, and the connectivity of devices. This is probably the most challenging step for small utilities.
- If you don't already have detailed data for your feeders, start by installing monitoring equipment. The data gathered will help identify infrastructure weak points and allow you to stay ahead of demand for new distributed generation.
- For utilities without extensive monitoring or advanced metering infrastructure (AMI) in place, a good hosting capacity approximation can be obtained using SCADA and conductor data. Supervising control and data acquisition (SCADA) can be used in conjunction with circuit power-flow models to understand loading throughout the circuit.
- Many solar developers operate nationally and are used to receiving certain information from utilities in the areas with higher penetrations of distributed resources. They will expect the same level of information as they enter new markets.
- Help commissions, boards, and developers understand what data are available and keep them apprised of the constraints and limitations identified in the distribution models. If you don't yet have the data for a more detailed analysis, work to obtain the data and keep the models updated with where you are in the process.

What is considered high penetration?

Any level of distributed generation (DG) that does not change the voltage or the current (typically less than 10%) would be considered low penetration. Generally, anything above 10% is considered high penetration. More than 10% DG on a circuit can significantly alter voltage and current. So a model is important so as to understand the impact of those resources on the circuit. Lower penetrations can typically be accommodated without significant circuit upgrades.

What utilities are doing

In California

As part of the DRP process in California, utilities were directed to explore an enhanced hosting capacity analysis or Integration Capacity Analysis (ICA) and to determine the location value of these resources through a Locational Net Benefit Analysis (LBNA). Evaluation of these methodologies was to be explored through pilot Demonstrations A and B, which were specified in each utility's DRP (see page 26 for more information on the DRP process). The goal of these pilot demonstrations was to provide a clearer picture of where resources could be cost-effectively added to serve the distribution system. To support the utilities as they executed the Demonstration A and B pilot projects, the CPUC established the ICA and LNBA Working Groups. Information about California's DRP, ICA, and LNBA working groups can be found at <http://www.drpgw.org>.

Demonstration A pilots focused on evaluating an ICA methodology that would evaluate the limits of the distribution system to host DER across an entire portion of a utility's service territory. The utilities were to test and evaluate approaches for determining the hourly integration capacity of DER at each line section or node using an Iterative and Streamlined approach for two scenarios: 1) no backflow and 2) maximum DER capacity irrespective of power flow direction. The ICA calculations were performed for 576 hours over a 12-month period using one day per month of both typical high-load and low-load conditions (12 months × 24 hours × 2 profiles = 576 real-time, historical points). The ICA looked at thermal overloads, voltage violations, protection, and reliability and safety limitations.

SCE, SDG&E, and PG&E have submitted final reports to the CPUC on their findings and results. These reports can be accessed at <http://drpgw.org/sample-page/drpgw/>.

Southern California Edison—Evaluating the ICA (Demonstration A)

Under their Demonstration A pilot, SCE is evaluating the ICA in two distinct distribution planning areas (as required by the CPUC ruling): a rural area in Tulare County, CA, and an urban area in Orange County, CA. The two service areas together include 8 distribution substations and 82 distribution feeders serving a representative mix of customer types (residential, commercial, industrial, and agricultural).



Heat Maps

Heat maps allow developers to easily see which areas of a circuit have high penetrations of DER. However, developers are often driven more by market demand rather than the information on the maps. So, even when provided this information, developers may not want to change plans, preferring to pay for the necessary system upgrades over relocating the project.

The Streamlined Method calculates one power-flow simulation for each hour in the analysis, whereas the Iterative Method performs multiple power-flow simulations with varying levels of DER connected to each node. The Iterative Method is similar to what SCE uses in its interconnection process. SCE determined that the Streamlined Method could produce results more quickly, but the Iterative Method generated more accurate results. The accuracy of the Streamlined Method depended on the complexity of the distribution system and it was found that it could yield sub-optimal results.

The model incorporates all existing generation (PV, combined heat and power [CHP], or any type of generation). The result of the analysis is an hourly profile hosting capacity curve for ten different DER types and specific profiles that show how much DER can be integrated on every line section at every hour throughout the year. The curve can be modified based on the technology type to be interconnected and will provide the hosting capacity for each node. SCE is also looking into smart inverter capabilities and how they can apply that to the hosting capacity analysis. The intent is to test the capability of SCE's tools and system maps to eventually perform the ICA on all circuits. SCE sees that the most immediate use of the ICA values is to help speed up the interconnection process in addition to helping with planning and forecasting.

In light of the ICA analysis results from the Demonstration A pilot, SCE has proposed the implementation of a Blended ICA method across its territory. The Blended Method would use the Iterative Method on the typical 24-hour, light-load day while utilizing the Streamlined Method for the full 576 hours.

One challenge is how much information can be provided in the online map because SCE has about 2.7 million nodes. SCE is trying to determine what information can be provided and how it can be displayed or shared. SCE is looking at updating the hosting capacity map monthly because updates require that the entire analysis for all the feeders be rerun to include updated information on circuit changes.

Pacific Gas & Electric—Getting the Right Data for ICA

Getting the right data fed into the models—and making sure they were scrubbed and had the appropriate detail to complete the ICA—proved to be challenging for PG&E. Additional challenges were also associated with understanding the picture presented by the data and filling in the gaps where it was lacking. Simply obtaining the information on the devices—such as capacitor settings, regulator settings, and phasing data—can be difficult, not to mention ensuring that the settings are properly modeled in the database. However, without these data, developing accurate distribution power flow-models is nearly impossible.



One particular challenge was getting the phasing information correct. PG&E found instances where clusters of solar units on a single phase with a regulator seeing reverse flow would exacerbate voltage deviations even though the other phases were fine. PG&E is looking into automatic phase detection to obtain the necessary (i.e., accurate) phasing information.

Generation data are also an area where PG&E is developing a better understanding including how much generation data are needed for an accurate ICA. With solar units, they are investigating whether it is necessary to know tilt, azimuth, facing direction, as well as the type and model of the installation. PG&E is trying to determine what details are needed with regard to smart inverters and their settings, and how to properly account for that information, especially in their distributed energy resource management system (DERMS), where the information is needed to properly account for the resource.

PG&E's ICA filed with the CPUC can be found [here](#).

Across the Nation

National Grid—Saving Time and Money

National Grid is performing a hosting capacity study and creating a circuit map that will indicate levels of circuit hosting capacity for each feeder. The goal is to provide the information that customers and developers need prior to submitting an interconnection application. National Grid defines hosting capacity as the amount of distributed generation that can connect to a distribution circuit without any (not even minor) upgrades. National Grid sees several benefits for publishing the information; however, the primary benefit will be to reduce pre-application information requests by giving developers and customers basic feeder information, such as voltage, load levels, and the hosting capacity for each feeder. Currently, responding to pre-application requests, which are free in Massachusetts, requires significant staffing and can be costly.

National Grid has committed to the Massachusetts Department of Public Utilities that they will have hosting capacity for 50% of their distribution feeders by the end of 2017 and all distribution circuits by the end of 2018, with plans to update the analysis two times per year.

National Grid is using [GridLAB-D](#) for the network model and EPRI's DRIVE (Distributed Resource Integration and Value Estimation) tool for the hosting capacity analysis. One of the challenging first steps to performing the study is to ensure data model accuracy. National Grid worked for the past two years to ensure that the data in their model were accurate and current, the correct inputs had been used, and the outputs generated make sense. The DRIVE tool has 12 criteria that can be used to calculate hosting capacity, and the inputs depend on specific feeder characteristics and utility design parameters. Although National Grid uses CYME as the planning tool to model its circuits for load-flow analysis and planning, GridLAB-D allows them to model each individual feeder with more detail on component performance.



Example of Pepco hosting capacity map showing different feeder capacity levels.

National Grid has three departments that work together to perform the hosting capacity analysis. The Advanced Data and Analytics Department models the feeders in GridLAB-D, the Planning and Asset Management Department runs EPRI DRIVE, and the Asset and Data Analytics Department takes the output from the tool and develops the circuit maps. Individuals within the departments perform hosting capacity functions along with other responsibilities.

Pepco—Helping Developers Plan

Pepco is performing hosting capacity for their radial circuits and secondary network. They are doing this as a planning tool for developers. They have [a restricted circuit map](#) and recently added [a hosting capacity map](#) to better assist developers in determining good locations for solar installations. The maps are updated quarterly and posted to the website.

Pepco performs the hosting capacity studies for their radial circuits using a tool they developed by EDD as part of the Distribution Engineering Workstation power-flow analysis program. Initially, the study was performed using 20 representative circuits, but it was then expanded to include all Pepco Holdings, Inc. (PHI) radial circuits (around 1550). To perform the analysis, they first run a base case on the circuit “as is,” which includes PV that is already installed on the feeders and any expected infrastructure changes. The tool then uses a Monte Carlo simulation method to randomly add PV until a voltage violation occurs. A strict penetration limit occurs at the level when the first randomly placed PV causes a violation. The maximum penetration limit is established when any additional randomly placed PV causes a violation. The results indicate the amount of PV that the entire feeder could accommodate if the PV is randomly placed. Results are an approximation because the analysis does not take into account the exact location of where the PV would be installed or the exact sizing. The hosting capacity analysis is rerun whenever the feeder becomes restricted/unrestricted or for every 500 kW of installed solar that is connected to a feeder (either in aggregate of smaller applications or one large application).

Pepco does not use the hosting capacity for the interconnection application process, but has chosen to perform a power-flow-based analysis combined with other automation to review each application instead. A power-flow analysis is more accurate in assessing grid impacts and will demonstrate any issues that will occur on the circuit; hosting capacity analysis will not highlight all issues.

The hosting capacity methodology for the secondary low-voltage AC networks is performed using customer hourly interval data obtained from AMI. Hourly PV outputs are estimated based on clear-sky irradiance and the system size, location, orientation, and time of day. Pepco then analyzes each secondary spot network and secondary grid or area network to determine the maximum solar generation that can be added. One critical analysis point is based on the maximum ratio of hourly PV output to gross load.

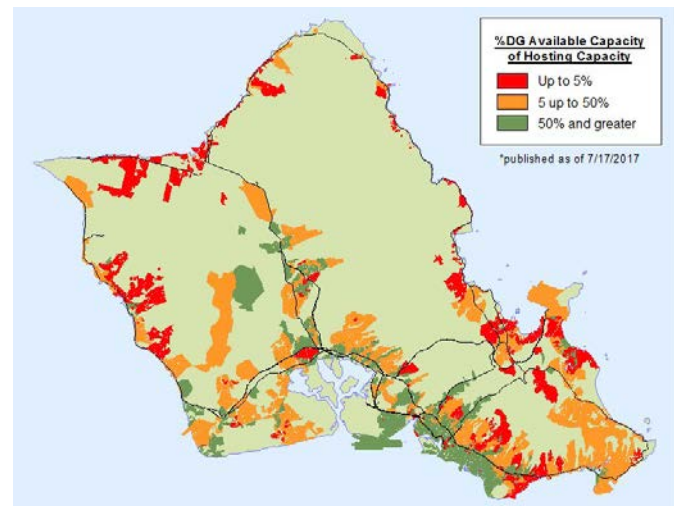
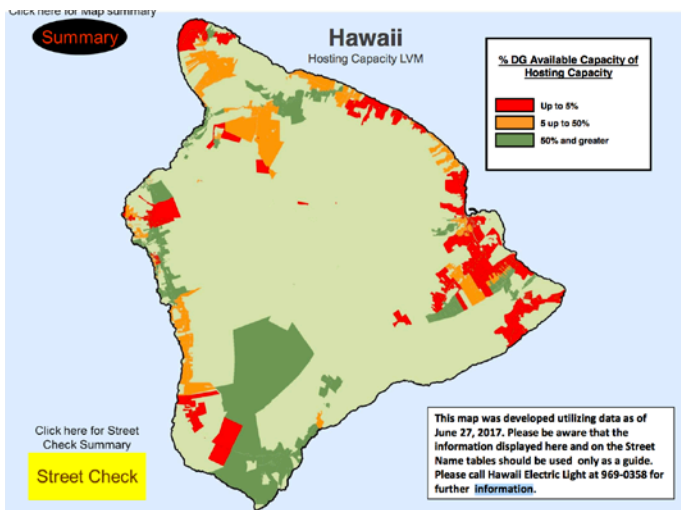
Pepco found that preparation of circuit model and correct mapping of hourly load plus the verification of the results has required more manpower than originally anticipated. It can be a time-consuming task for some circuits. The average time per circuit was about 20 minutes for radial circuits and about 2–4 hours to do the complete secondary network (model was much cleaner) fed by around 250 primary circuits. Data quality is the main factor and as the model and customer load mapping improve in accuracy, the effort to do hosting capacity will be reduced significantly.

Hawaiian Electric Company—Performing Daily Updates

Hawaiian Electric Companies (HECO) started looking at hosting capacity several years ago as they began to experience increasing penetrations of PV on their distribution system. Prior to that, they looked at the circuit penetration using the 15%-of-peak rule as a criterion for interconnection, then transitioned to using 50% of daytime minimum load, then 75%, 100%, 120%, and 250% as more information and technologies became available to mitigate concern; however, they determined that different feeder characteristics and infrastructures impact how much PV (or DER) a circuit can handle. HECO now uses their hosting capacity studies to more quickly process interconnection applications. HECO updates the locational value maps daily that are on the website.

HECO built their circuit model in Synergi, which feeds into the hosting capacity tool that was developed in-house. The tool runs an analysis of all primary circuits (from the substation to the transformer). The circuits include any PV systems even if that system has not yet been installed. To create the location maps, HECO runs the analysis annually and as needed, and the tool provides an allowable amount of PV that can be easily interconnected for the entire circuit from the substation to the transformer and a system below the threshold can be installed anywhere along that circuit. The map is updated daily based on new applications that are approved.

HECO updates the location map daily and each interconnection application is evaluated against





the capacity threshold for that circuit. If the installation size is greater than the hosting capacity limit, the interconnection application goes for supplemental review to look at the application location and how that would specifically impact the circuit.

In addition to the hosting capacity analysis for the circuit on the primary side, for each application HECO reviews for other possible conditions—including using a voltage rise/drop calculator, which is a spreadsheet model, to evaluate the impact on voltage on the secondary side (from the transformer to the customer). This analysis is necessary because the secondary side can experience voltage violations due to the PV installations and a lack of diversity factor on the transformer because most PV customers tend to generate maximum output at the same time—typically midday rather than at various times throughout the day. (Diversity factor is a ratio of the maximum output of all of the systems at any given time to the sum of the non-coincident maximum out of each individual system.)

Salt River Project—Using EPRI Drive

Salt River Project (SRP) has performed hosting capacity studies on all of its 1,400 feeders. SRP serves about 1,000,000 customers with an average solar penetration of 2% although some feeders have much higher penetrations. Feeders are typically between 2–5 miles long and are looped.

SRP models their distribution system using Synergi. The EPRI MAI (Model A Interface) tool is used to extract and manipulate the Synergi model data to create files that can be used by the EPRI DRIVE tool, which provides the actual hosting capacity results. The conversion by MAI is the most time-consuming part of the hosting capacity analysis. Evaluation of 1,400 feeders can take up to 40 hours; therefore, SRP evaluated smaller planning areas with about 100 feeders each and stores the files for future use by DRIVE. This method proved to be more manageable and efficient.

During the initial studies, SRP evaluated its distribution feeders in a normal configuration. However, other configurations will be evaluated as needed for specific studies such as new large solar interconnections and extreme weather days. The newest version of EPRI DRIVE will include existing PV installations on the feeder in the evaluation, so SRP will update its Synergi model to include existing solar and redo the analysis using this new capability on future studies.

Additional Resources

EPRI's DRIVE: Although utilities use a variety of methods to calculate hosting capacity, one tool that many are using is EPRI DRIVE. (Utilities in New York agreed to use DRIVE, which will then feed into each utility's planning tools.) DRIVE uses a non-iterative method to calculate the amount of DER that can be accommodated in a specified area to identify issues and to assess mitigation solutions. EPRI is currently developing additional tool capabilities and has created interfaces to a number of utility planning tools. (See Appendix B for more information on DRIVE.)

More resources cited by the working group include:

- Sandia National Laboratories Report, [Alternatives to 15% Rule](#)
- EPRI Report: [Distribution Feeder Hosting Capacity: What Matters When Planning for DER?](#)
- EPRI information on [Distributed PV Monitoring and Feeder Analysis](#)

Selecting the method for calculating hosting capacity

Which method to use to determine hosting capacity depends primarily on the amount of data and the desired application of the results. Consider what the analysis will be used for to determine the granularity that is needed. Using representative circuits will work for R&D and policy; interconnection and planning require a higher level of detail.

Testing Advanced Inverters

Advanced (or smart) inverters are a technology that may help utilities better integrate customer-owned distributed generation. Because the advanced functionality is relatively new, utilities are using field tests and demonstration projects to better understand how the inverters can be used to support their operational objectives.

Traditionally, utilities have used line regulators and capacitors to keep voltage within certain limits. Advanced inverters are another tool utilities can use to support voltage and power quality, and mitigate system issues created by increasing penetrations of renewable resources.

Utilities with high penetrations of customer-site generation are investigating how to effectively (and securely) communicate with and control smart inverters; how these devices might be used to mitigate fluctuations in voltage, current, and frequency; and how they can best operate on their own and in conjunction with other devices and control methods employed by the utilities.

While this initiative did not include a comprehensive look at the many advanced inverter pilot projects taking place across the nation, the examples provided by the working group participants illustrate some of the different system designs and functionalities being studied, as well as a variety of study methodologies and approaches. Information and data gleaned from the advanced inverter pilot projects will help the industry better understand the capabilities, benefits, and limitations of these promising tools. However, it is necessary to read the studies carefully. The details are important and can impact results.

Biggest Challenge: Robust communications capabilities and standard protocols to optimize advanced inverter functionalities.



Lessons from pilot projects and inverter testing

- Programming is different for different inverter manufacturers. Some differences include:
 - + or - can mean either leading or lagging depending on the manufacturer.
 - For 0.9 power factor (PF), some manufacturers use .9 and some use 9000.
- An inverter PF setting doesn't necessarily go through 0 when a utility needs to shift from producing to absorbing VARs.
- Some inverters are easier to program than others and allow more clearance for linemen to work. When evaluating inverters, look at what it will take to program the inverter.
- Be aware that the technology is still maturing.
- Protocol is a big issue. Many manufacturers use their own proprietary version of Modbus.
- Underwriters Laboratories (UL) certification process for advanced inverters is challenging.
- Robust inverter standards are needed for advanced inverter technology.*
- More collaboration is needed between the vendors and the utilities to work through the technical challenges.
- Firmware updates can be challenging.
- Utilities need to determine what is necessary versus what is optimal.

*Note: IEEE 1547 will address some of these issues, but more standards are needed.

What utilities are learning

- Advanced inverter functionality behaves differently depending on feeder characteristics.
- More robust communications systems are needed for the monitoring and control of real-time operations of customer generation.
- Communicating with inverters on the system, such as sending new settings, is not a trivial issue. Most inverter manufacturers use proprietary software and protocols and have their own approach to programming.
- Modbus is not a secure protocol and has significant limitations. A new protocol may be needed. Utilities are working to develop approaches to keep their networks secure when communicating with devices using Modbus.
- Testing can provide greater understanding of how the inverters really work and what it will take to program them—which can be different for different manufacturers. It can even uncover limitations that manufacturers weren't previously aware of.
- Some inverters may not retain remote setting changes. One utility found that when the sun sets, the inverter would turn itself off and reset to the default settings. Another found that once the programmed period expired, the inverter reset to default settings rather than adjusting to the new set point.
- Some inverters will only provide reactive capacity when the sun is shining. This could be a significant issue from a voltage violation perspective. For example, if the inverter is maintaining voltage but the set point resets at sunset, unexpected voltage deviation could occur.
- Make sure you define what “real time” means to avoid latency issues. What real time means to utility operators is not necessarily what real time means to network providers. For one utility, real time was 100 milliseconds, but the inverter manufacturer interpreted real time as 1–2 seconds.
- Some utilities are deciding to bring the communications work they had previously outsourced to contractors in house so they can have more reliable monitoring.
- Advanced inverters are capable of collecting readings for Watts, VARs and current. However, a reading from an inverter is not as accurate as a reading from a meter, and can be off by 1%–3%. The question is whether the inverter reading accuracy is within acceptable limits for operations.
- When thinking about advanced inverters, don't lose sight of the bigger picture. Although addressing issues on the distribution system might be the most immediate need—and installing a limited number of advanced inverters might mitigate these issues—transmission impacts should also be considered. With higher penetrations of distributed generation, it may be necessary to have advanced inverters on all installations to avoid negative impacts on transmission.
- Cost trade-offs of inverter solutions versus traditional electromechanical solutions might be different on a new circuit designed with high penetrations of PV in mind, compared to a legacy circuit designed without that criterion.
- The technology (i.e., inverters, communication paths, controllers) is not mature and is still under development, and firmware updates can be a big problem. Many firmware updates must be done in the field and cannot be remotely updated. This can be time consuming and costly.

What utilities are doing

SRP—Retrofitting Existing Customers' Inverters

Salt River Project, an Arizona utility, is seeing its grid transition from one with centralized generation to one with increasing amounts of generation owned and located in its customers' backyards. To accommodate this change, SRP launched an inverter pilot study to explore system design changes, and inverter settings, communications, and control requirements that will allow it to continue providing quality service while minimizing costs for all customers.

The pilot study included installing a test bed designed to resemble a residential system. The test bed proved useful in informing the selection of inverters for the project, determining project objectives, and identifying potential issues before involving the customers.

Using insights from the test bed, SRP is evaluating these three scenarios:

1. Set and Forget: Provide given set points for 400 customers' inverters.
2. Limited Communication: Send seasonal changes to settings for 250 advanced inverters.
3. Full Communication and Control: Perform real-time communications and control using a mini advanced distribution management system (ADMS) to control 120 advanced inverters on a single circuit.

The third scenario is being tested on a circuit that is connected to a substation with a large commercial PV system. With the scaled-down approach for this scenario, SRP hopes to gain a better understanding of how to optimize voltage profile and power quality using advanced inverters in coordination with the mini-ADMS, prior to rolling out a full-scale ADMS.

The SRP project is unique in that it focuses on retrofitting existing solar customers' inverters in a community that already has a high penetration of rooftop solar systems. It is also the first study of its kind to evaluate advanced inverters from the customer's side of the meter. The pilot study results thus far provide a number of valuable insights:

- Educate customers upfront about the study, including [FAQs](#) on retrofitting and firmware updates. SRP posted information on its website and held focus groups prior to the study. It found that many solar customers were interested in participating because they wanted to help SRP learn how to connect and manage more solar on its grid.
- If the solar company handling the retrofit is different from the original installer, it could void the solar system warranty. Developing good relationships with local installers and engaging them in the project helped mitigate warranty issues.
- SRP installed a dedicated generation meter at each customer site so that customers can view on their portal the amount of energy their system produced the day before, and SRP can know exactly what is happening with the PV system.

The pilot study involves 20 different departments, making internal coordination important.

There are many variables that affect the results of pilot studies, including the type of inverters used, what is being measured, and the characteristics of the system. When reading reports about other demonstration projects, remember that the devil is in the details.

Duke Energy—Identifying Latency Issues

The overwhelming majority of solar installations connecting to Duke Energy's grid are distribution-scale (between 1 and 5 MW). These distribution sites are primarily third-party owned and operated. Duke began constructing a 80-MWdc (about 60-MWac) transmission-connected system in 2015 that came online by early summer 2016.

Duke's primary objective at this site was to implement dynamic voltage response to transients at the point of interconnection, with the goal of responding to transients within 100 milliseconds (6 cycles). After completing construction however, Duke Energy found there were roundtrip latencies in the communications network around 1–2 seconds. This baffled its engineers because they were using a fiber network where communications happened in microseconds.

After reaching out to the inverter manufacturer, Duke Energy discovered that when a set point is received at the inverter, it takes the inverter 200–250 milliseconds to implement the set point. This unexpectedly long latency proved a significant obstacle, and the difference in perceptions of real-time between the utility and the manufacturer made achieving the project goal infeasible. It should be noted that due to the pace and advancement of inverter technologies, the manufacturer(s) could have addressed latencies in newer firmware/models.

The lesson learned is that even in an ideal network with absolutely no latency, there would still be inverter latency. Although Duke Energy's project was transmission-scale, a similar issue would occur at the distribution level if a utility were trying to do a communications-based voltage response with some algorithm or power-plant controller.

Arizona Public Service—Investigating Advanced Inverters, IVVC, and Energy Storage

Under the Solar Partner Program (SPP), Arizona Public Service is conducting a large, two-phase study to determine whether advanced technology can be used to help manage voltage rise on feeders caused by high penetration of rooftop solar. Three technologies are being investigated: advanced inverters, integrated Volt/VAR control (IVVC), and battery storage. Goals of the SPP study include an evaluation of: 1) advanced inverters and their ability to reliably perform grid services, 2) IVVC and its ability to flatten and lower voltage to compensate for PV-caused voltage rise, and 3) batteries and their ability to do these same functions. The first phase of this study—the testing and evaluating of advanced inverters on high-PV penetration feeders—was completed in 2016 in partnership with the Electric Power Research Institute (EPRI). The second phase, which involves the IVVC and battery investigation, is expected to be completed in 2017.

In the first phase, APS implemented direct, real-time control of advanced inverters using UL1741-SA advanced-inverter functions to provide voltage- and power-quality support, including adjustable power-factor control. APS elected to implement a Siemens-provided SICAM controller to realize central control from its distribution operations center. This allowed communications to be handled over both public cellular (via VPN) and private AMI networks to manage cybersecurity risk.

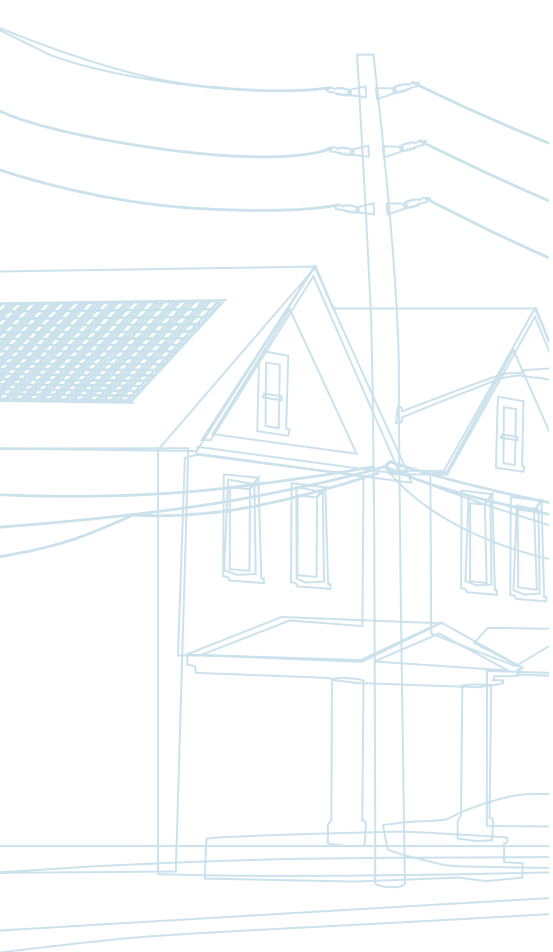
Get involved with standards. Standards are being developed and updated to include advanced inverter functionality. This work is important and the utility perspective needs to be represented in that discussion.

Phase 1 (2016) research focused on six high-penetration feeders and included high-resolution data collection at the substation, midpoint, and end of the feeder to monitor feeder conditions.

Additional details of the study including the following:

- APS recruited about 1,600 homes to participate. The 4- to 8-kW systems in the study are owned by APS and include solar panels, an advanced inverter, and a connection to the utility-side of the meter. APS will maintain the systems throughout their lifetime (20 years). The program is free to homeowners, and APS provides a \$30 monthly credit on participating customers' bills.
- APS used a combination of cellular modems and AMI radios for the communications pathways back to the control room. The cell modem pathway was seen as lower risk but also a less sustainable communication pathway in the long term due to costs (about \$5–\$10 per month, per customer, for the data package). The AMI-network pathway has the potential to be a more sustainable pathway because the utility owns the communication network. About 1,000 inverters use the AMI pathway and 500 use the cellular pathway. APS also compared the latency and reliability between the two communication pathways.
- Early in the study, APS noticed that inverters were disappearing from the system. They soon learned they had to program the inverters to turn off at night and then turn back on in the morning. Distribution operators entered new settings each morning which, although cumbersome, reflected the state of the still-evolving controls landscape for distributed technologies.
- APS built predictive models so it could validate those models against the data received in the field.

In Phase 2 (2017), APS will be looking at storage and IVVC with capacitor banks to manage voltage, power factor, and peak demand in addition to two battery energy storage systems (BESS). Each BESS is 2 MW, 2 MWh in size, and is installed on one of the six primary research feeders. The first BESS is located directly adjacent to the substation of a research feeder and the other is located about midway down a different feeder. The study has been designed to evaluate the effectiveness of advanced real-power and reactive-power functions of the storage units in various combinations with and without advanced inverters and IVVC.





SDG&E—Investigating Aggregator Control and Inverter Capabilities

When monitoring a large PV system in 2011, SDG&E found that there was significant variability on the line causing primary distribution voltage deviations well outside ANSI range A. Given California's clean-energy goals—and anticipated penetration levels—and what they were seeing with voltage deviations, SDG&E realized there could be significant operational issues in the future as penetrations increased. Wanting to be proactive, SDG&E worked with the CPUC to establish the Rule 21 Smart Inverter Working Group (SIWG). (Note: Beginning on September 8, 2017, in California, all inverters will be required to have the seven Rule 21 Phase 1 functions that were recommended by the SIWG and adopted by the commission. Work in the pilot was based on discussions from the working group.)

SDG&E, in a pilot project with SolarCity, set out to test smart inverter functionality and explore the ability of these inverters to help manage the voltage profile on circuit. The objective of the pilot was to evaluate inverter capabilities for controlling voltage and to demonstrate the ability to communicate with the aggregator. SDG&E selected a new community in a highly urbanized, residential area with relatively short feeders (4 miles) and peak loads of around 6–7 MW. The area chosen had 1 MW of installed PV with standard inverters, and 465 kW of PV were installed with advanced inverter functionality for the study. Additionally, the inverters were rightsized so that at power factor limit the inverters were able to provide 100% rated power output.

SDG&E looked at two approaches for using smart inverters to provide reactive-power support: fixed power factor and dynamic Volt/VAR control using three curves (a progression from a deadband to no deadband). SDG&E sent out the set points on a schedule to the aggregator, who would then send these signals to the inverters. The communications protocol from SDG&E to the aggregator was IEEE 2030.5 (i.e., ZigBee 2.0), the protocol the California inverter owned utilities settled on. As part of IEEE 2030.5, a naming convention was developed so it would be possible to communicate down to a single transformer with a logical node approach. This was done so there would be an addressable structure for SDG&E to request the performance if dispatching from a DERMS product.

SDG&E demonstrated that it is possible to send an aggregator a schedule with the appropriate identifiers specifying what was needed at a specific location on the circuit, and the aggregator could implement that scheme. SDG&E also found that the dynamic Volt/VAR modes do a much better job of controlling the secondary voltage than when operating at a fixed power factor for an extended period. They did not find, however, that there was any impact to the primary—which is where utilities currently regulate voltage.

Insights that SDG&E shared with the working group include:

- On a circuit that has a mix of traditional and advanced inverters, there won't be as much of a benefit from advanced inverters unless the penetration levels are high and the benefits will be different than if all PV systems on the circuit have advanced inverters. For SDG&E's study, although the circuit had both standard and advanced inverters, only the advanced inverters were monitored. The project evaluated the capabilities of the advanced inverters to modify the voltage ranges.
- SDG&E had observability of the primary distribution system via SCADA at the distribution substation breaker, at the midpoint switches, and along the line. Looking these data, they didn't see any impact to the primary distribution voltage, but results showed that the smart inverter could help modify the secondary distribution voltage.
- SDG&E anticipates that in the future there will be weather-based voltage regulation schemes. They are looking at possibly scheduling various kinds of weather modes such as clear day, cloudy day, and intermittent day.

Potential risks with aggregator control of inverters

- Each aggregator could be a point of failure.
- Aggregators could be interested in also aggregating thermostats and other devices, which would introduce another point of failure.
- Aggregators may not have the resources or practices in place to address cybersecurity issues required by the utility.

Engaging the Customers

Rooftop solar system owners are different from the traditional electric customer. Really different. Solar customers tend to be highly engaged, have many questions, and want detailed information—in real-time—preferably accessible through their phone. With a passion for renewable energy, these customers will likely require a high-level of information and customer service to answer questions and guide them to the right decisions.

It is also not just about rooftop solar systems. Across the country, utilities are developing a variety of tools and resources to help their customers make informed decisions about buying “green” power. This includes everything from how utilities are greening their generation portfolios to providing opportunities to participate in community solar projects and helping customers decide whether owning a rooftop solar system is the right choice for them. Utilities understand that they can play an important role in providing

timely, accurate, and unbiased information to their customers, as well as the solar installers and developers working in their communities.

One challenging aspect of communicating with customers is managing their expectations—topic that emerged in nearly every conversation. Managing customer expectations is an important part of customer communications that goes beyond providing accurate information to addressing incorrect assumptions customers may have that

could be influencing their decisions. It can be a delicate area for customer services representatives to navigate!

The bottom line is that today utility customers expect lots of information and utilities are not only responding, but proactively engaging their customers and stakeholders in discussions that can help them make the best decisions.

Biggest Challenge: Meeting customers’ changing expectations and becoming a trusted advisor on customer-owned generation.



What utilities are learning

- **Customer education is important.** Even knowledgeable customers may not fully understand or may have misinformation about the interconnection process and system limitations. Part of the education process will be about managing customer expectations. It is important to help customers understand how much their system will actually generate (and that it could differ depending on the time of day or year) and what this could mean for their bill. Adding a note to their interconnection application approval documentation can be a good way of communicating this.
- **You will need more than a website.** Having information available on a website is expected, but regular webinars and workshops with customers and installers are also an effective way to educate your stakeholder community and can make the interconnection process simpler for contractors and customers. Getting in front of customers and contractors will help build relationships and improve understanding. You may also need to invest in marketing programs to direct customers to your website, webinars, and seminars.
- **Solar customers have a need for LOTS of information that is easy to access.** Remember this when designing tools for them. (Consider providing an app for your solar customers.) Customers who have paid to install a PV system want it to begin producing energy as soon as it is installed; however, there are typically additional steps before the system can be “turned on,” such as the county inspection, meter exchange, and contractor documentation. Make sure timeframes for each step of the process are clearly communicated to customers.
- **Knowledgeable, competent customer service representatives are imperative.** Some solar customers are very energy literate. They want (and need!) information on technical concepts such as the net metering tariff, grid constraints, how their PV system will perform, and other complex technical concepts (such as transformer overload). Customer service reps should be prepared to provide simple, clear explanations to the questions that customers are sure to ask.
- **Be aware of the incentives and policies driving customer choices.** Customer service representatives must understand and explain the importance of right-sizing rooftop solar systems, and know that often the system size a customer is requesting is being driven by state policy incentives. When customers oversize their systems, it can create operational issues for the utility—something customers don’t usually understand.
- **Take the time to answer all their questions.** Whether it is a single point of contact or a specialized team of customer service representatives, utilities must be able to respond to solar customers with accurate and timely information. This includes taking the time needed to help customers understand how their PV systems will perform, what type of utility bill they will get (some customer do not understand they will still get a monthly bill), and what is required for installation.
- **Solar installers tend to be the primary source of information for rooftop solar customers.** Hence, your communications strategy should include programs and materials that target the installers—they can be your biggest advocates—as well balance out some of the misinformation that consumers may be receiving.
- **Help customers understand their new bill.** Customers don’t always realize that their bill might be different from their neighbors because they don’t necessarily use energy like their neighbor. If their neighbor installed solar and has a low energy bill, they will want the same. They don’t always recognize that the neighbor might have a lower bill because they are out of the house all day, have fewer household members, or have a roof that faces in a better position to match energy demand. It is important to help customers understand how much their own system will actually generate (and that it could differ depending on the time of day or year) and what this could mean for their bill.

What utilities are doing

There are many examples of utilities whose websites explain how solar works and what is required to interconnect to the distribution grid. There are tools to help customers calculate their energy needs, size their systems, and find solar contractors. There is information on pricing plans and understanding their bills, understanding financing options, and maintaining and monitoring a rooftop system. Here are some examples of how utilities are engaging their customers and stakeholders and helping them to make informed decisions.

Providing easy-to-understand information upfront: How-to, right-sizing, and pricing

If customers have better information early on, they can make better choices. Providing reliable guidance from the get-go reduces customer frustration, manages expectations, and produces better outcomes for everyone.

- Georgia Power has a [simple tool](#) on its website to help customers assess their home's potential for solar power generation.
- SCE's [Guide to Going Solar webpage](#) provides information about installing rooftop solar, with easy steps for customers to follow.
- SRP's website has a [one-stop landing page](#) that includes residential and commercial solar information, price plans, a demand calculator, and rebates for solar water heating.
- PG&E has an [online tool](#) where customers can calculate their potential solar savings.
- Pepco is using the online solar calculator [WattPlan](#) to help customers understand their properties' solar potential; right-size their system; provide information on rates, costs, and installation; and answer FAQs. More than 5,000 people have used Pepco's calculator since it went live.
- HECO provides [locational value maps](#) to show customers and solar contractors the distributed generation levels on their circuits. The information on the maps is updated daily.
- Providing clear answers to frequently asked questions is always a good idea. The more location-specific, the better. Pepco's [FAQ webpage](#) for its Washington D.C. customers is one example.





Communicating beyond the website: Seminars, webinars, videos, and more

There's no question that a website can be one of the most powerful tools to engage customers. But with the complexity around solar, a good website alone is typically not enough. Develop a variety of tools and ways to reach out for the best results.

- In Massachusetts, three utilities have rotating monthly meetings for their customers as well as developers and installers where they talk about various topics. Each utility takes a turn hosting and the location is moved around. Around 700 invitations are sent for each meeting. The utility uses these events to communicate and provide the rationale for things like technical changes, updates on program limits, and new interconnection requirements. Technical staff members typically attend and answer customer questions directly.
- Pepco uses common issues and questions that it sees in its call center to guide topics for monthly webinars for customers, developers, and installers. Topics covered include net metering, the interconnection application and review process, and online application training. Contractors can also request a [face-to-face meeting](#) with Pepco personnel for a hands-on review of the interconnection application process.
- [APS](#), [SDG&E](#), [HECO](#), and [Kauai Electric Coop](#) have developed flyers and brochures to help customers right-size their systems, understand points of confusion, and maximize their savings.
- [SCE](#) and [HECO](#) created videos about going solar that go over how to get a PV system approved, installed, and connected.
- SCE developed a [video](#) and HECO created a [guide](#) to help customers understand net energy metering.

Customer service done right: Solar customer call centers and specialists

No matter how many creative ways you give solar information to your customers, sometimes there is no substitute for talking to a real person one-on-one.

- PG&E established a dedicated call center for solar customers. The utility found that with the growth of solar in its service territory, it really needed to have specialized customer service representatives who were knowledgeable about the interconnection process and could answer all solar-related questions. PG&E noted that this dedicated call center approach has led to a much better customer experience.

- With low but increasing penetrations, Pepco established a dedicated call center staffed with about 20 representatives just for customers with questions around PV installations. This is the same team that also processes the interconnection applications. This approach proved effective; however, if PV installations continue at the current rate—one in four of their customers is expected to have PV in the next two years—Pepco will reevaluate how best to direct these calls (dedicated call center versus main call center).
- Westar Energy has a dedicated representative for its solar customers. This allows Westar to offer personalized service from the initial inquiry through interconnection.
- Georgia Power also has a dedicated renewable energy group to answer customers' more detailed questions. This group is trained to help customers evaluate various Georgia Power solar program options and potential energy and bill savings with a solar installation.

Educating customers about curtailment

In 2015, Kauai Island Utility Cooperative (KIUC) had over 30 MW of utility-scale solar and 16 MW of customer-sited solar PV with a significant percentage of members continuing to install oversized systems. With a daytime peak load between 50–60 MW and wanting to continue to allow all members interested in installing solar to be able to do so, KIUC implemented a curtailment meter requirement program on systems that were considered oversized. The curtailment program requires all oversized systems to have a second AMI smart meter (KIUC provides the meter and the customer pays for the installation) with remote connect and disconnect capability on the customer's house to give KIUC the ability to disconnect the oversized system from exporting power to KIUC's grid. KIUC sends a signal to this meter and shuts it off when curtailment is required, then turns it back on when the curtailment period ends. The customer gets power from KIUC during the time the system is curtailed. If customers would like to continue to generate their own power during the curtailment event, they must separate the oversized portion of the system so that only it is subject to curtailment.

KIUC implemented an aggressive customer engagement campaign to educate consumers about the program and the importance of right-sizing their solar installation. KIUC wanted to be clear that it was not trying to discourage solar and that the curtailment program would not prevent anyone from installing an oversized system. It simply requires that a meter be installed on the oversized system so that KIUC can temporarily disconnect it from the grid when solar output exceeds demand. KIUC has created several brochures and posters as part of the education campaign. (See Appendix C for examples from KIUC.)



Appendix A

DOE Integrating Intermittent Resources Working Group Participants

This list includes all parties who registered for a working group conference call, attended a regional meeting (or sent staff to one of the meetings), or participated in an interview with the leadership team. The leadership team would like to thank everyone who supported this initiative, especially those who shared their experience with the readers of this guide.

Ahmad Ababneh Pacific Gas and Electric Company	Ellen Burt Stowe Electric Department	Babak Enayati National Grid
Amrita Acharya-Menon Pepco Holdings	Anthony Cadorin City of Mesa	Frank Etori VELCO
Greg Adams Salt River Project	Josh Castonguay Green Mountain Power	Ken Fong Hawaiian Electric Company
Gred Anderson Otter Tail Corporation	Jim Cater American Public Power Association	Don Ford Westar Energy
Marc Asano Hawaiian Electric Company	Andrea Cohen Vermont Electric Cooperative	Deena Frankel VELCO
Manual Avendano Commonwealth Edison Company	Karen Collins Salt River Project	James Gibbons Burlington Electric Department
Shay Bahramirad Commonwealth Edison Company	Molly Connors, ISO New England	Fred Gomos Commonwealth Edison Company
Ed Batalla Florida Power & Light Company	Steven Cook Rochester Public Utilities	Stewart Grantham North Carolina Electric Membership Corporation
Michael Beaulieu Vermont Electric Cooperative	David A. Crabtree Tampa Electric	Adrienne Grier Commonwealth Edison Company
Thomas Bialek San Diego Gas & Electric	John J Cruz Jr. Guam Power Authority	Christine Halquist Vermont Electric Cooperative
David Bonenberger PPL Corporation	Joel Danforth Platte River Power Authority	Robby Hamlin CoServ Electric
Rita Breen Georgia Power	Kent Davenport Delta-Montrose Electric Association	Robert Harris National Rural Electric Cooperative Association
Dennis Brown Pepco Holdings	Robert Dostis Green Mountain Power	Daniel Haughton Arizona Public Service Company
Dustin Brown CoServ Electric	Erik Ellis Arizona Public Service Company	Bobby Hawthorne Southern Company
Cyrl Brunner Stowe Electric Department	William R. Ellis Pepco Holdings	

Edward Hedges Kansas City Power & Light Company	Matthew Liethen Commonwealth Edison Company	Jonathon Rhyne Duke Energy
Michael Henderson ISO New England	Joel Linton Florida Power & Light Company	Patty Richards Washington Electric Cooperative
Foster Hildreth Orcas Power and Light	Shana Louiselle VELCO	Kristin Riggins Kansas City Power & Light Company
Anthony Hong Hawaiian Electric Company	Lisa Magnuson Pacific Gas and Electric Company	Carol Robertson Village of Hyde Park Electric Department
Larry Hopkins Piedmont Electric Membership Corporation	Alan Matthews Seattle City Light	Brad Rockwell Kauai Island Utility Cooperative
James Hurtt Florida Power & Light Company	Jeff McKeever Otter Tail Corporation	Marc Romito Arizona Public Service Company
Tim Jarrell Cobb EMC	William Mintz Southern Company	Chris Root VELCO
Ferhaan Jawed Pacific Gas and Electric Company	Alan Mosher American Public Power Association	John Roukema Silicon Valley Power
Kerrick Johnson VELCO	Catherine O'Brien Salt River Project	Benjamin Rushwald Seattle City Light
Ken Kagy Cedar Falls Utilities	Esa Paaso Commonwealth Edison Company	Tom Russell Pacific Gas and Electric Company
Vanessa Kisicki Salt River Project	Lena Perkins City of Palo Alto	Roger Salas Southern California Edison
Kandice Kubojiri Hawaiian Electric Company	Dean Phillips FirstEnergy Corporation	Scott Scharli Salt River Project
Robert Kondziolka Salt River Project	Steven Pigford Southern Company	Joe Schatz Southern Company
Robin Lanier Georgia Power	Leslie Ponders Duke Energy	David Schoeberg Pacific Gas and Electric Company
Casey Lamont Burlington Electric Department	David Quier PPL Corporation	Jeffrey Schoenecker Dakota Electric Association
Benjamin Lee Southern California Edison	Cory Ramsel Florida Power & Light Company	Rick Schroeder North Carolina Electric Membership Corporation
Karen Lefkowitz Pepco Holdings	Tammie Rhea Westar Energy	Mark Sciarrotta VELCO

Uzma Siddiqi
Seattle City Light

Grant Smedley
Salt River Project

David Smith
Florida Power & Light Company

Darren Springer
Burlington Electric Department

Steve Steffel
Pepco Holdings

Robert S. Stewart
Pepco Holdings

Chase Sun
Southern California Edison

Erik Takayesu
Southern California Edison

Jim Taylor
Tucson Electric Power

Jacob Tetlow
Arizona Public Service Company

Steve Thompson
Southern Company

Scott Tjaden
Pepco Holdings

Louis Vitola
Delaware Municipal Electric Corporation

Joe Walligorski
FirstEnergy Corporation

Jim West
Snohomish County PUD

Eric Wong
City of Palo Alto

Michael Yamane
Kauai Island Utility Cooperative

U.S. Department of Energy Team

Tanya Burns
Arara Blue Energy Group LLC

Sonja Berdahl
National Renewable Energy Laboratory

Eric Lightner
U.S. Department of Energy

Appendix B

EPRI's DRIVE

Purpose

Distribution Resource Integration and Value Estimation¹ (DRIVE) is an EPRI-developed tool that enables distribution engineers with new planning methods that assess the Grid of the Future. The primary focus is to integrate and value new distributed energy resources (DER).

Functionality

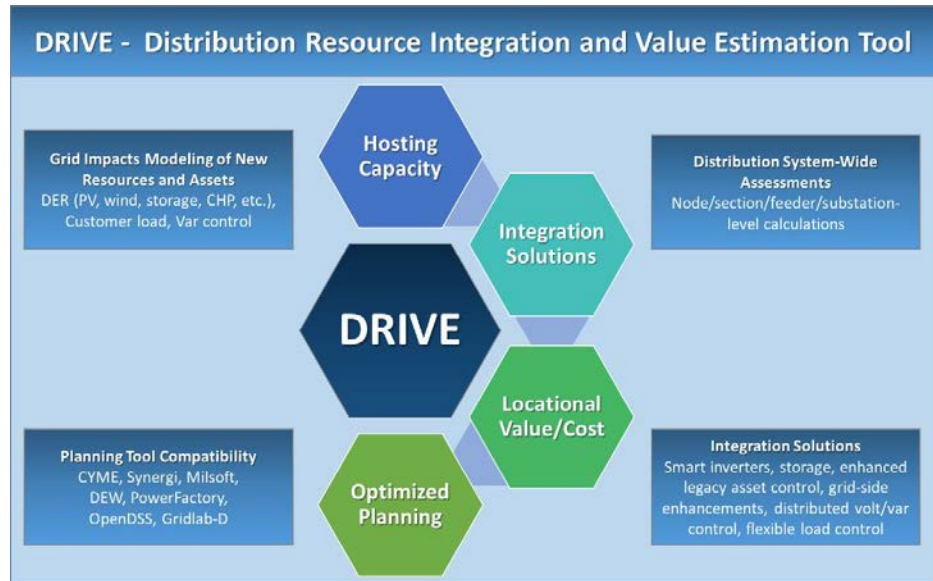
The goal of the DRIVE tool is to build on the hosting capacity analytics to identify constraints and potential integration solutions as part of the planning process. This includes evaluating both the technical impacts and the locational value/cost. In order to achieve full DR integration and value estimation, DRIVE must be able to consider²:

- **DER scenario analysis:** evaluating a range of deployment scenarios and their impacts is an important part of the planning process. Being able to develop scenarios that consider different DER, locations, and load levels enables assessment of both where DER may cause an adverse impact as well as where and how DER can be used as a non-wires alternative (NWA).
- **DER forecasts and load growth:** assess load growth as part of the annual planning to account for the potential increase in DER hosting capacity. Additionally, as DER forecasts become more granular, planners can assess the potential impact from DER deployment in specific locations and at specific levels. Considering DER forecasts and load growth together will improve the planning process.
- **Reconfiguration:** considering reconfiguration of the distribution system can increase and decrease hosting capacity. This will be a critical function to consider as part of planning as Distribution Automation (DA) becomes more prominent.
- **Integration solutions:** Assessing the wide range of integration solutions as part of the interconnection and planning process is critical to identify the least-cost solutions for integrating DER. Grid impacts vary (voltage, thermal, protection) and the most effective and least-cost solutions or suite of solutions are unique to the DER characteristics and the power system design and operating criteria.

These are just a few of the capabilities being actively developed and refined as part of the DRIVE tool that are necessary to realize full integration and valuing of new resources in concert with existing assets to achieve an optimized planning process.

DRIVE Implementation

DRIVE is a comprehensive, non-iterative methodology that expedites the analysis process. This enables a tool that meets certain criteria in terms of scalability, replicability, and compatibility without compromising accuracy³.

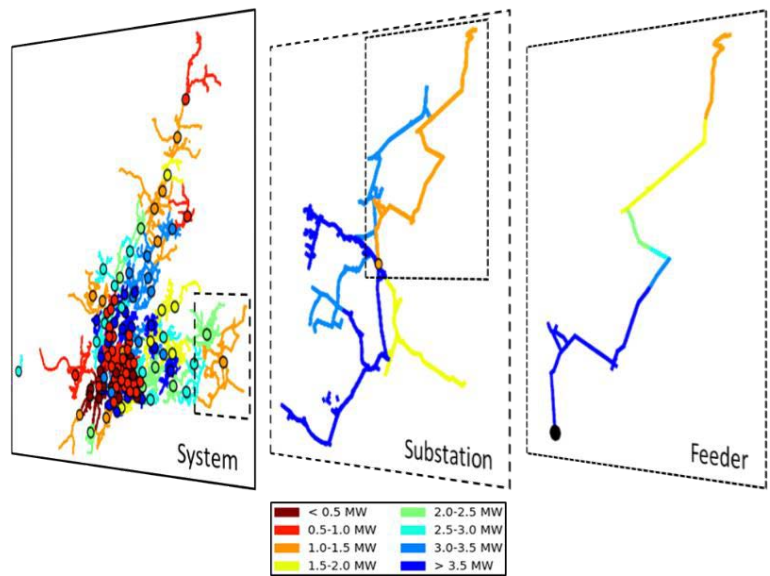


¹ M. Rylander, "Distribution Resource Integration and Value Estimation," presented at the IEEE Photovoltaic Specialists Conference (PVSC), Portland, OR, 2016, pp. 1–5.

² Rylander, M., Smith, J., "Advancing Distribution Planning Tools for DER Impact Assessments: Streamlining DER Hosting Capacity Analysis," 6th International Workshop on Integration of Solar Power Into Power Systems, 14-15 November, 2016, Vienna, Austria

³ Demonstration of Improved DER Screening Using the Hosting Capacity Method, EPRI, Palo Alto, CA: 2016. 3002008294

- **Scalable:** DRIVE can be utilized across an entire distribution area in a reasonable amount of time. System-wide hosting capacity calculations cannot take weeks-to-months to perform as it would put undue burden on resources and limit its applicability.
- **Replicable:** DRIVE allows planners to re-analyze circuits to consider reconfiguration, long-term changes in load/configuration, mitigation strategies, smart inverters, DR deployment scenarios, etc. This is essential to using the tool in modern distribution planning.
- **Compatible:** DRIVE has been implemented in a range of utility planning tools (e.g., CYME, Synergi, Milsoft, PowerFactory, OpenDSS, DEW, Gridlab-D, etc) enabling consistent methods.



Applications

With these functionalities and implementation, DRIVE can enhance system planning. Currently, the main application is to identify how much DER can be accommodated (hosting capacity), what issues arise, and assess integration solutions to mitigate the issues. Additionally, it can be used to inform interconnection screening and planning decisions.

Table 1. Applications of DRIVE

	Applications of DRIVE
Node/Section/Feeder/Substation-level hosting capacities⁴	Determine hosting capacity on each feeder under current and future grid configs. Improve substation-level capacity visibility.
Improve fast-screening techniques	Improve screening techniques that efficiently account for the proposed DER and associated grid capacity at that location
Increase Hosting Capacity	Improve planning techniques by identifying opportunities to increase hosting capacity across the system.
Identify system impacts and costs to integrate DER	Provide visibility to specific technical issues, mitigation options, and costs.
Optimize DER integration value	Provide visibility to locational benefits, minimized costs, and potential values.
Aggregate DER for bulk system	Identify locations and aggregate DER for bulk system studies

Next Steps

In order to further enhance the DRIVE tool, EPRI will be launching a new DRIVE Users Group to facilitate input and improvements to the development of functionality. The users group will bring together utility planners and planning tool vendors with an end goal of full commercialization

Contact Info: Matthew Rylander, mrylander@epri.com

⁴ A New Method for Characterizing Distribution System Hosting Capacity for DER: A Streamlined Approach for PV. EPRI, Palo Alto, CA: 2014. 3002003278.



Options for Sizing Rooftop Solar

1. Right-sized

The criteria are based on the average monthly kilowatt-hour usage of the household. The average household uses about 25 percent of its electricity between 9 a.m. and 3 p.m., so any system that produces more than is needed to offset the household's daytime demand could be considered oversized. With the understanding that all customers have different needs, KIUC developed this chart that defines as right-sized a system that produces more than 25 percent of a household's energy but is not designed primarily to export energy to the grid. Right-sized systems do not require a curtailment meter.

Right-Sizing Criteria	
Average monthly usage in kWh	Maximum PV Size
0-500	2.5 kW
500-800	2.75
800-900	3.00
900-1000	3.5
1000-1100	3.75
1100-1200	4.25
>1200	5.25

2. Oversized

An oversized system is designed to serve the household or business and to export energy to the grid. As of Nov. 17, 2015, KIUC will require a second meter on the system that enables the utility to limit the amount of energy being exported during times of peak solar generation. Curtailment of solar will occur when there is more electricity being produced on the grid than there is demand for it. In that event, KIUC sends a signal to the meter and shuts off the rooftop system, then turns it back on when the curtailment period ends. When the system is curtailed, it will not export energy to the grid and solar power also won't be available for household use. Power to the home will come from KIUC during the curtailment period. Oversized systems are required to use KIUC's standard wireless meter. KIUC will supply this second meter but the cost of installation is the customer's responsibility.

3. Oversized split

A customer can separate the rooftop system so that only the oversized portion is turned off during a curtailment event; the household can still draw solar power from the portion of the system that is right-sized. For example, a house that needs a 3.5 kW system but installs a 7.5 kW system can split it so that only the oversized portion (4kw) is shut off during a curtailment event.



FAQs on curtailment and right-sizing rooftop solar

During the daylight hours, more than 70 percent of the electricity generated by Kaua`i Island Utility Cooperative can come from solar. That's the highest percentage of solar on any grid in the U.S., maybe even the world.

But there's a physical limit to how much solar can be put on the grid. As more oversized residential photovoltaic systems come online, there's less room on the grid for future residential solar and cheap utility-scale solar. That's why KIUC encourages "right-sizing" of rooftop systems so they don't generate a lot more electricity than the household uses.

For those who still want to buy an oversized system that exports energy to the grid, KIUC is requiring a shutoff device that enables the utility to limit the amount of energy being exported during times of peak solar generation. This new requirement affects only systems installed after Nov. 17, 2015.

This limiting, known as curtailment, occurs when the power generated by solar photovoltaic systems exceeds the demand for electricity. For example, on a cool and sunny Sunday afternoon when solar power generation is at its peak, consumption of electricity is at its minimum. Supply and demand of electricity must be in constant balance to maintain the stability of the grid.

How does curtailment work?

A second electric meter is installed on your house to give KIUC the ability to interrupt power flowing from your rooftop solar system. KIUC sends a signal to this meter and shuts it off when curtailment is required, then turns it back on when the curtailment period ends. You won't notice when it happens. When the system is curtailed, it will not export energy to the grid and solar power also won't be available for your household use. You'll still be connected to the grid, so you'll be getting power from KIUC during the time your system is curtailed.

Why now?

Only 10 percent of KIUC's members have solar, but their systems can generate nearly 22 megawatts of electricity. That's a lot when you consider the peak demand for electricity on Kaua`i is only about 72 megawatts, and that peak occurs at night. When rooftop solar started, systems were sized to offset the household's daytime electric use to reduce the utility bill. Now, most rooftop systems are significantly oversized for the purpose of selling

electricity to KIUC - some are 5 times larger than what the household needs. This leaves less room on the system for future installations. And some of this electricity can cost more than the electricity generated by KIUC's solar arrays and some of its hydroelectric plants. It doesn't make sense for all of KIUC's members to pay a higher price for electricity that isn't needed.

Are you doing this to discourage people from installing solar?

No. This action leaves room on the system for members who want to install solar in the future. This doesn't prevent anyone from installing solar. It doesn't even prevent anyone from installing an oversized system. It simply requires that a meter be installed on the system so that KIUC can temporarily disconnect it from the grid when solar output exceeds demand. A customer also has the option of separating the system so that only the oversized portion is turned off during a curtailment event; the household can still draw solar power from the portion of the system that is sized to the home's average usage.

When will curtailment occur and how long will it last?

There's no set schedule. It depends on the weather, the demand for electricity and the availability of KIUC's generating resources. Curtailment would typically occur on clear, sunny days when demand for electricity is relatively low - usually on weekends. It could last for a few minutes or for several hours.

Does that mean my power will be shut off?

No. Curtailment affects only the energy produced by rooftop solar. You're still connected to the grid, so you'll get your electricity from KIUC during the curtailment period.

What formula do you use for determining the size of systems?

The criteria are based on the average monthly kilowatt-hour usage of the household. The average household uses about 25 percent of its electricity between 9 a.m. and 3 p.m., so any system that produces more than that could be considered oversized. With the understanding that all customers have different needs, KIUC developed this chart that allows for solar systems that produce more than 25 percent of a household's energy but are not designed primarily to export energy to the grid. These systems are considered to be right-sized and do not require a curtailment device.

Right-Sizing Criteria	
Average monthly usage in kWh	Maximum PV Size
0-500	2.5 kW
500-800	2.75
800-900	3.00
900-1000	3.5
1000-1100	3.75
1100-1200	4.25
>1200	5.25

November 2015



You're smart with your money.

You wouldn't buy a \$60,000 SUV if all you needed to get around was a \$20,000 compact, right?

The same should go for rooftop solar systems.

That's why we recommend getting a system that's right-sized for your household, not oversized.

For the average household, KIUC recommends a 10-panel system producing 2.5 kilowatts to offset your daytime electric use. You should first consider a solar water heater, which is a lot less expensive to install and can reduce your electric bill by 30 percent or more - and KIUC offers a \$1,000 rebate.

If you have questions about how much electricity you're using, or want advice on right-sizing a rooftop solar system, call us at 246.4300.

WHAT THE SOLAR GUYS MAY NOT TELL YOU

Not everyone needs a \$25,000 solar photovoltaic system.

Installing a solar water heater is the cheapest, easiest way for most Kaua'i households to save at least 40 percent on their electric bill.

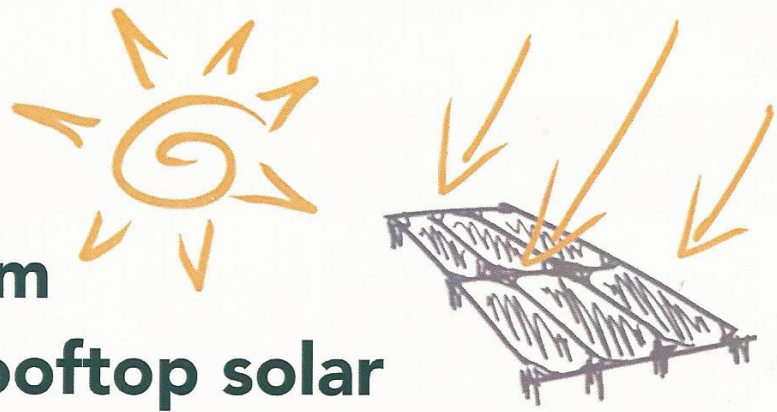
Water heaters use more electricity than any other appliance. Using the sun to heat water can save you around \$80 to \$100 a month, maybe more, depending on the size of your family.

Right now, KIUC is offering a \$1,000 rebate toward the purchase and installation of a solar water heater. With the rebate and state and federal tax credits, your final cost could be less than \$2,000.

So do the math yourself and see how much money you can save just by using a solar water heater.



Straight talk from your co-op on rooftop solar



As a co-op, we support measures our members can take to save money and become more energy efficient.

We also want our members to make informed decisions about their energy use. With rooftop solar photovoltaic systems being sold so aggressively on Kaua'i, we're already seeing situations where people aren't getting the savings they were promised. So now they're paying a KIUC bill and making monthly payments on a solar lease.

There are also people who use very little electricity who are being talked into long-term leases for big rooftop systems. In some cases, their lease payments can be more than their old electric bill.

Rooftop solar isn't right for everyone, so it's important that you get all the facts before buying a system or committing to a lease.

If you do decide to get a rooftop system, we recommend getting one that's right-sized for the amount of electricity your household uses, not oversized. The bigger the system, the higher the cost. And there's no guarantee KIUC will always buy your excess power.

Here are the co-op's answers to some common questions about rooftop solar:

Should I get a rooftop solar system?

It mostly depends on how your household uses electricity. To maximize your savings, your household must be able to shift a significant amount of its electricity use to the hours when

the sun is shining – doing laundry or cooking during the day, for example. If no one is home during the day and your energy use during those hours is minimal, your savings will also small.

What size should my system be?

Every household uses electricity differently, but the average household using 500 to 700 kilowatt hours per month can usually achieve savings with a 10-panel system producing 2.5 kilowatts. For people using less than 500 kWh per month, the savings probably aren't big enough to justify the cost of rooftop solar. You should first consider a solar water heater, which is a lot less expensive to install and can reduce your bill by 30 percent or more – and KIUC offers a \$1,000 rebate. You can call us at 246-4300 and we'll tell you what your average use is.

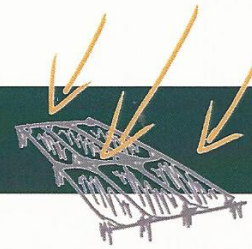
How many panels do I need to make my bill go away?

Even customers who offset all of their household use still have to pay a minimum monthly charge. An oversized system designed mainly to sell excess electricity to KIUC can cost \$40,000 or more before tax incentives – the bigger the system, the longer it takes to recover your investment, if ever.

Those zero-down leases sound like a great way to get solar on my roof

With zero money down, you're rolling the cost into the monthly payment you'll be making to the solar company, which charges you for the

Straight Talk



electricity your system produces. Before signing a long-term lease, ask yourself some questions: Do I plan to live here for 20 years or am I going to move? Am I comfortable with the risk that if the price of electricity falls, I'm still locked into a higher lease payment? Can I shift my use of electricity to the daytime? What kind of warranty does the contractor provide, and who will be around to repair my system if it breaks 10 years from now?

How much will KIUC pay me for the excess electricity I generate?

For most members with rooftop solar, the amount KIUC pays for the electricity they export to the grid changes every month, depending on the price of oil. It's been as high as 26 cents and as low as 10 cents. This rate, known as Schedule Q, reflects the amount KIUC would have had to pay to generate the power if we didn't buy it from you. Because KIUC generates most of its electricity by burning oil, this so-called "avoided cost" calculation is tied to the oil price. As more renewables come on line and KIUC burns less oil, the amount paid under Schedule Q is expected to drop.

Will KIUC always buy the extra energy my system produces?

On a sunny afternoon when all of the photovoltaic systems on the island are at their maximum output, there can be more power

being generated than there is demand – there's nowhere for this excess power to go. So there may be times when our system won't accept all of the solar power available. That's known as curtailment. The more oversized rooftop systems on the grid, the more likely curtailment becomes. KIUC hopes to avoid curtailment by encouraging customers to install "right-sized" systems. At times when peak solar production outpaces demand, it's possible KIUC may temporarily disconnect some oversized systems so they can't export to the grid.

Will the charges on my electric bill stay the same if I have solar?

People with solar photovoltaic systems are still on the grid. They count on it to provide 80 percent of their power, since those systems don't work at night and when it's cloudy. Yet they pay a smaller share of the utility's fixed costs – people, poles, lines, power plants, batteries – than people without PV. Regulators have acknowledged that existing rate mechanisms don't reflect the new reality of renewable resource integration. Some Mainland utilities are starting to charge PV customers a fee to help recover their share of fixed costs and Hawai'i utilities, including KIUC, are studying similar fees. Any rate changes would be subject to the approval of the Hawai'i Public Utilities Commission.



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