Distributed Energy Resources: Managing Growth with Digital Agility

How three utilities across the country are leveraging software technology to enable business goals
Across the U.S., distributed energy resource (DER) implementations are growing fast. Some states are on track to meet their near-term renewable energy goals early. However, the process of integrating DERs with utility distribution grids doesn't always go smoothly. From shifting system peaks to intermittence and the complexities of managing virtual power plants, DERs pose many grid challenges as well as opportunities.

In three North American regions that are facing very different DER challenges, Siemens has been collaborating with utilities to develop innovative, customized technology strategies to accommodate DER growth — anticipating future needs, and addressing problems that didn’t exist a decade ago. The following case stories offer an inside view into those unique challenges and solutions.
Hawaii has the nation’s most favorable economics for solar power. Historically, electricity has been far more expensive in Hawaii than in the mainland U.S. Plus, the tropical climate offers abundant solar resources. These factors have combined to make every kind of solar power production, from photovoltaic (PV) rooftop panels to large solar farms, an attractive investment in this state. On a sunny, relatively cloudless day, distributed solar may comprise up to 40% of the total generation for a Hawaiian island.

Consequently, Hawaii was the first state to achieve near grid parity for solar energy. It also has been exceeding its Renewable Portfolio Standard (RPS) goals. The Hawaiian Electric Companies provide electricity to 95% of the people in the state and, in 2016, 26% of power used by these customers came from renewable resources, easily beating Hawaii’s 2015 RPS goal of 15%. By 2030, the state has a 30% renewable energy target — but it’s likely this goal will be reached far earlier, mostly due to solar growth.

“Even though most of Hawaii’s solar systems are very small, in aggregate, solar is effectively the largest generating resource on our island grids,” said Colton Ching, Vice President of Energy Delivery for Hawaiian Electric. “It’s three times larger than any of our conventional generators.”

This quickly posed severe challenges to local distribution grids. By mid-morning, there’s a steep drop of load demand as rooftop solar floods Hawaiian Electric’s grids. Then, as the sun sets and people come home from work, load ramps up quickly.
This creates what’s been dubbed the “Nessie Curve” — because, unlike California’s “Duck Curve” (in which solar PV generation reduces but does not erase demand), Hawaii’s demand drops “underwater” during peak solar production hours. Additional DER complications in Hawaii include rapidly changing weather patterns (which make forecasting difficult), as well as a lack of backup systems on several islands.

In July, Hawaiian Electric filed with the state’s PUC a revised proposal for grid modernization. The utility’s initial proposal was rejected for not being sufficiently cost effective. The new proposal leverages advanced technologies to cut projected costs by $135 million, through measures such as adding sensors and automated controls at the substation and neighborhood circuit level, as well as expanding the communication network to provide greater operational visibility and efficient coordination of DERs.

“We had very little direct vision into what DER generators are doing, or what they are going to be doing in the next time increment,” said Ching. “We don’t have a way to control or dispatch solar generation.”

In a new DOE-funded initiative, Integrating System to Edge-of-Network Architecture and Management (SEAMS), Hawaiian Electric is working with Siemens to demonstrate enhanced utility visibility and control of electricity resources across its distribution networks. Leveraging Siemens Spectrum Power™ Energy Management System software, Hawaiian Electric is proving integration to edge-of-network resources, as well as developing new functionality to manage DERs.

“This project will allow us to evolve and grow our current architecture, to help manage this new resource which is a completely different animal in our system,” said Dora Nakafuji, Hawaiian Electric’s Director of Renewable Energy Planning and System Integration Department.

“In the past, we didn’t have too much monitoring because customers mostly consumed the power they produced. But today, far more customers are contributing power to the grid,” Nakafuji explained. “This new architecture reliably transfers information from the grid edge, so our operators and planners can have visibility to anticipate change and manage the system in real time.”
NEW JERSEY

PSE&G: Utility Planning for Solar Impact

Challenge: Significant solar growth feeds fears of grid unreliability
Solution: Siemens Distribution Network study leads to locational and capacity recommendations for new solar installations

The Garden State has become a hotbed of solar growth, thanks to affordable land in southern NJ, plus DER-friendly utilities and regulators. Public Service Electric and Gas (PSE&G), the state’s largest and oldest investor-owned utility, offers particularly ambitious solar development programs. Solar 4 All is developing 158 MW of grid-connected solar by building utility-scale solar farms and the world’s largest pole-attached solar project. Also, PSE&G provides affordable customer financing for rooftop solar systems.

But how much more solar can the state’s existing grid safely accommodate without negatively impacting system reliability? PSE&G was concerned about the cumulative effects of a vast but dispersed solar influx to its 13 kV network — the same network that serves most of its customer load.

“We wanted to study how all this solar growth might impact our customers,” said Ahmed Mousa, PSE&G’s Manager for Electricity Delivery Planning, Asset Management and Centralized Services.

Almost all distribution grids were built with centralized generation in mind. Bi-directional power flows can challenge grid assets and operations, especially for voltage and frequency regulation near large concentrations of solar PV. Also, traditional generation resources usually are not sufficiently agile to compensate for the intermittence of solar. In 2016, at a FERC conference on solar and grid reliability, it was noted that without significant grid modernization, local solar-related grid disturbances can move upstream to cause wider problems.
PSE&G hired Siemens Digital Grid Power Technologies International (Siemens PTI) to study this issue using their advanced distribution network simulation and planning software suite, **PSS®SINCAL**. Siemens evaluated current network constraints and PSE&G’s 13 kV DER hosting capacity and quantified PSE&G’s capacity limitations for renewable generation placement on the grid. A recent Utility Dive webinar showcased this study.

**THESE RESULTS INDICATED THAT 60% SOLAR PENETRATION WOULD BE SAFE FOR AREAS OF PSE&G’S GRID.**

Weather was a key consideration. When solar output is fairly constant, it’s easy for grid operators to accommodate that input. However, moving clouds cause PV output to fluctuate, making it harder for grids to adapt. Using **PSS®SINCAL** software, Siemens simulated a sunny day as well as a day of fast-moving clouds for PSE&G’s Lumberton, NJ substation, where a 5.5 MW solar farm, commercial rooftop plus a variety of smaller PV installations are connected. A time-domain power flow in second-domain resolution was performed to study the cloud impact to voltage variation (“voltage flicker”).

PSE&G provided Siemens with substantial load data and telemetry for the substation and feeder, including the locations of all connected solar installations. “The main goal was to find pockets of high or low voltage,” said Mousa.

This study also compared two simulation methods: the common approach (which assumes an instantaneous ramping from zero to full solar output), versus ramping that happens over a one-minute interval. Gradual ramping is a more realistic representation of cloud movement; it also takes a full minute for capacitor banks or substation transformer load tap changers to correct a voltage violation based on “time delay setting”. These results indicated that 60% solar penetration would be safe for areas of PSE&G’s grid.
PSE&G provided Siemens with a GIS based map of the system being studied. Siemens provided PSE&G with a detailed GIS-based map in SINCAL format. This study confirmed PSE&G’s 13 kV DER hosting capacity which allows more than 60% of the circuit’s capacity.

PSE&G now recommends that new non-residential solar PV interconnections should be able to regulate a +/-95% power factor. This helps the utility maintain proper voltage and enhance reliability for all customers.

“We also are recommending smart inverters for new solar installations with voltage VAR control capabilities,” said Mousa. “This allows a PV installation to ride the wave. A smart inverter can correct for high or low voltage on a circuit. It’s under the customer’s control, and it’s very efficient.” The power factor change and smart inverters recommendations will allow more solar interconnections without jeopardizing the integrity of the grid.

In the bigger picture, this sort of modeling supports more accurate forecasting and resource planning — supporting more cost-effective wholesale power transactions as well as long-term capital investment strategies. Siemens is helping many utilities learn how to integrate DERs more effectively into planning processes.

For PSE&G, the next step is to evaluate the potential for battery energy storage to complement DERs and support grid operations. “We’re going live soon with a distribution management system that gives us much more visibility into the grid access and the impact of DERs,” said Mousa. “That will allow us to connect even more renewables without hurting the grid.”
**MIDWEST**

**Wabash Valley Power: Building a Better Virtual Power Plant**

**Challenge:** Managing demand response events for greater system performance  
**Solution:** Evolve into a comprehensive DER management system

DER’s encompass more than renewable generation and energy storage systems. They can also include the system capacity provided by demand response events such as peak shaving, load shifting, thermal energy storage and more. When coordinated effectively and reliably, such resources can form a virtual power plant (VPP) — direct capacity that can be offered on the wholesale power market.

Since the 1980s, Wabash Valley Power Association (a nonprofit generation and transmission co-op serving 23 rural distribution co-ops in Indiana, Illinois and Missouri) has operated a diverse and robust demand response program. Mostly, this involves direct control of mainly residential loads, such as water heaters, irrigation pumps, air conditioning units, and even entire homes. Currently Wabash can control 55 MW via demand response.

“Direct load control has always counted as a DER to us,” said Andrew Horstman, Manager of Load Response for Wabash. “All of these programs are measured and communicated a bit differently. They all have rules; we only had to worry about scheduling events. That was our baseline.”

In 2013, Wabash deployed Siemens’ EnergyIP demand response management system (DRMS) to manage execution of load control events. This yielded good results, which in turn led to several incremental upgrades of the system. Then, in 2016, Wabash worked with system integrator Omnetric Group to substantially upgrade and expand the system’s capabilities into a true DER management system (DERMS) application.

Sachin Gupta, Senior Sales Executive for Omnetric Group, observed that the
DERMS application helps future-proof member co-ops. “They need to be ready for DER penetration, and they need a more holistic view on demand response,” he said. “Wabash needed to extend the value proposition of demand response, to leverage it for more advanced applications.”

**“INITIALLY, THE MAIN REASON WE DECIDED TO EXPAND OUR DRMS CAPABILITIES WAS TO AUTOMATE AND STREAMLINE OUR EXECUTION OF DEMAND RESPONSE CONTROL EVENTS.”**

Andrew Horstman, Manager of Load Response for Wabash

Currently, the Siemens DERMS application has been integrated to all Wabash member co-ops, across six different advanced metering infrastructure (AMI) systems and two different customer information systems (CIS).

“Initially, the main reason we decided to expand our DRMS capabilities was to automate and streamline our execution of demand response control events,” said Horstman. “And also to more accurately measure and verify demand response performance — both for reporting back to our member co-ops and their customers, and to validate registrations with our ISO.”

The DERMS application provides fully integrated, end-to-end data management, from data capture to billing. It calculates the baseline and settlement determinant, applies the appropriate pricing incentive, and produces a billing determinant for issuing payments or penalties.

Wabash was quick to explore the extra opportunities afforded by the system expansion. “The more information we got, the more stuff we were able to do,” said Horstman. “We started adding different rules on different functions and events, to compare methodologies and see which worked best. We’re experimenting with options beyond direct load control, especially with commercial accounts. We’re customizing the types of messages and notifications sent to customers for these programs, so we can talk to customers more effectively.”

The DERMS also gives Wabash far more granular control over demand response resources. “In the past, utilities had few options for dispatching loads,” Gupta explained. “If they needed to relieve load at a specific sub-station, or congestion in a certain grid sector, they were never able to target only that load with conventional demand response. With Siemens’ DERMS application, they can create custom load groupings to strategically target loads — right down to a specific device behind a specific meter — for a variety of purposes. They can also dispatch events manually, or allow an ISO or secondary utility trigger a load for dispatch.”

“I don’t know if any other system, like SCADA, could go this deep into a cus-
customer’s home to control devices, not with this level of measurement and notification,” said Horstman. “I don’t think there’s another system that does so much on the back end: AMI, analytics and execution across a wide range of devices. Siemens’ DERMS lets us make more decisions on the data we’re getting.”

So far, Wabash’s biggest challenge with deploying their DERMS application has been consolidating and standardizing data collection. “We’re collecting customer and load data across almost all of our co-ops. They’re all different organizations, and interacting with all of their different business processes is daunting,” said Horstman. “Whenever we think we have this licked, there’s always more to do.”

Currently, Wabash’s DERMS application interacts with very little solar or wind generation, but it is helping Wabash prepare for the Midwest’s increasingly renewable energy future. Renewable resources, from residential rooftop solar to a wind farm, can be added to the VPP, alongside demand response resources. None of the states where Wabash operates has a Renewable Portfolio Standard, but Wabash is conducting some early explorations to apply DERMS to renewables.

“We’re building some solar now, and DERMS is helping us monitor how it affects system voltage, so we can learn how to better manage the grid to accommodate solar,” said Horstman. “We might even take pricing into account for managing renewables. If the wind is blowing at night, why not deploy that energy to supercharge some water heaters at night to absorb that power? That would reduce the daytime demand from water heaters.”

Gupta noted that the Siemens DERMS includes forecasting algorithms to predict intermittency. This enables utilities to adapt to fluctuations in renewable energy output, perhaps compensating with demand response or other assets in the VPP.
Innovative Solutions addressing Emerging DER Challenges

DERs will likely always be a moving target. New technologies, business models, regulatory priorities, grid conditions and changing climate will continue to put pressure on utilities to evolve their strategies for deploying, managing and accommodating all kinds of DERs.

From experience working with utilities around the world, Siemens suggests a few key questions for utilities that are looking to optimize their increasingly distributed grid:

1. Does your Integrated Resource Plan accurately predict and support DER growth in your network? Does it account for locational capacity constraints and define required interconnection technology?

2. How much real-time visibility do you have into how DERs operate on your system? What might you be able to achieve if you could predict their patterns more accurately?

3. What are the long-term projections for renewable energy growth, demand, regulatory priorities, and grid capacity needs in your operational territory? How might DER management turn these factors to benefit your business model?

These case studies show how the Siemens Digital Grid portfolio includes a robust range of products and services to address DER challenges. Advanced control software such as DRMS and DERMS, distribution planning studies, and other offerings can bring value to distribution utilities — regardless of current or projected levels of DER penetration. Contact Siemens to learn more about how to expand your utility’s DER options and benefits.
Siemens Digital Grid partners with leading utilities and industrial energy consumers worldwide to provide expertise and innovative technologies. In North America, Digital Grid has worked with more than 1,000 energy customers to deliver proven solutions and services that improve operational efficiencies, enhance reliability and resiliency, and empower consumers to better manage their energy use.