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POWER NETWORKS

15 Symptoms of an Unbalanced Grid

The grid challenges outlined in this paper are complex, but there is a simple way to address all of them.

Have you ever seen the Mayo Clinic's online symptom checker? It's a click-through diagnostic tool that lets you choose a symptom, select related factors and then see possible causes for what's bringing you discomfort. Abdominal pain, difficulty swallowing, coughs, headaches, dizziness: Hey, there's a dizzying list of possibilities there.

This symptoms list is much shorter, but it's an important one for electric system operators to know. After all, reliability requires energy balance, a precise match between electric supply and consumer demand.

Read on for a look at 15 major symptoms that could mean the grid you're operating needs a checkup.

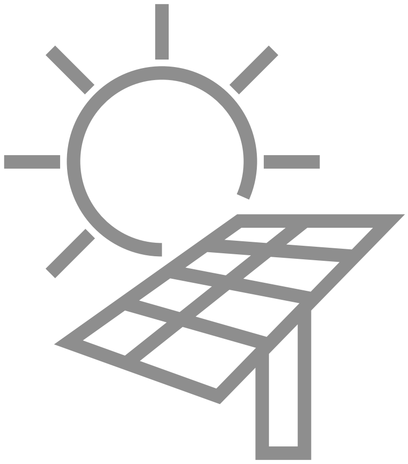
1. You have a backlog of solar installation approvals.

Customers may be signing up for solar PV in droves, but the wait to get those installations approved by the local utility can be a long one. For Arizona Public Service, the backlog has been hovering around 90 days, according to a February 2016 article in the Arizona Republic.

When cleantech analysts at EQ Research surveyed solar installers in the 13 U.S. states with the highest solar penetration, they found that the number of days that utilities took to give customers permission to operate their PV systems increased an average of 68 percent between 2013 and 2014. The researchers received data for 34 utilities, and 24 of those utilities were obligated to follow state interconnection rules that included permission-to-operate deadlines. In those jurisdictions, 14 of the utilities were in violation of regulatory mandates for timely interconnection approvals.

The National Renewable Energy Lab conducted similar research in 2015. Using data from more than 30,000 small commercial and residential PV systems across 16 states and encompassing 87 utilities, its researchers found a median timeline of 53 days from date the PV installer submitted an interconnection application to the time when that installer received the utility's permission to operate.

Such delays reflect the proliferation of photovoltaic systems and the strain it puts on utility processes. Chelsea Barnes, the EQ Research analyst who wrote her organization's report on utility interconnection timelines, forecasts longer and longer waiting periods as solar penetration levels rise "unless efforts are made to streamline the process."



2. You have increasing numbers of voltage excursions on your distribution network.

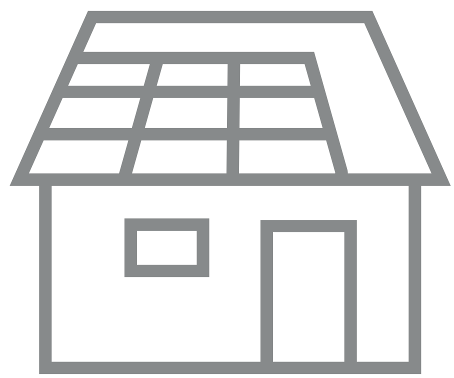
When you inject real power on a circuit, voltage rises at the point of coupling and drops in the direction of power flow as you move away from the point of coupling. When the injection of real power goes away or subsides – as it does when clouds cover a solar PV panel – the reverse occurs. Voltage drops, and it can drop instantly. That's why solar PV always has some impact on circuit voltage, which can be a problem when it's connected to the distribution system.

Customer-sited distributed generation can produce and feed so much power onto the local distribution grid that voltage rises beyond the ANSI standard of 1.05 pu. It's already been seen and caused much-publicized trouble in Hawaii, California, Germany and other locales. Naturally, it can go the other way, too. Voltage drops precipitously if sudden cloud cover rolls in or inverters trip off due to power-quality fluctuations.

Even very brief voltage excursions can be detrimental to customer equipment. A few years ago, a brief voltage sag stopped production at Hamburg, Germany-based Hydro Aluminum. The slowdown caused aluminum belts to snag and destroy other parts of the machinery, costing the manufacturer some $12,300 in damages. After voltage dropped twice more in the subsequent week, the firm purchased a $185,000 battery system, then sought damages from the local utility.

3. You are looking to install, own and operate distributed energy resources.

When Utility Dive surveyed 515 U.S. utility executives at the beginning of 2016, 94 percent said they believed utilities or their unregulated subsidiaries should be able to own and operate their own rate-based distributed energy resources (DERs). Sixty percent said they believed their utility should build a business model around distributed energy resources.



Why do utilities want their own DERs? It's primarily for control, but more specifically, they want device-level control. After all, utilities must deliver more than power. They also must deliver power quality and, if they own the generation or storage, they can control power quality fluctuations, particularly if they use smart inverters that have computing and communications technology built in. These devices can generate or absorb reactive power to raise or lower voltage. Similarly, smart inverters can be used to increase real power if frequency is low.

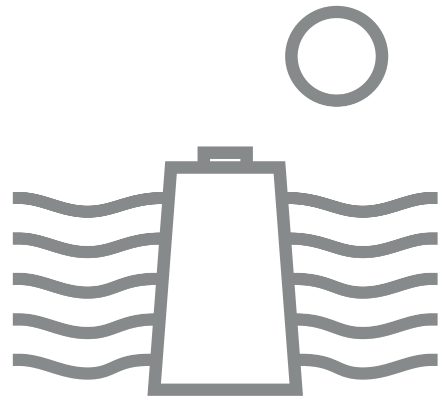
Utilities are also seeking control over where DERs are placed. Since consumers and PV installers generally want maximum energy output, they aim their solar panels south. In experimental programs, Tucson Electric Power and Arizona Public Service are paying consumers to install west-facing PV systems. At APS, that means installing free PV systems for homeowners with roofs that have an east-west pitch, then paying the homeowner $30 a month – $360 a year – to help the utility manage its peak loads by producing energy when the utility needs it. Tucson Electric Power has a similar approach. Rather than maximizing energy delivered, this methodology maximizes the value to the utility. It may also help reduce total greenhouse gas emissions.

The Pecan Street Research Institute found this approach to be a good way to address the need for end-of-day rapid ramping that so many utilities face because rooftop solar production goes down about the same time consumers are coming home and flipping on the air conditioner, lights, television and kitchen stove. According to Pecan's 2013 study, west-facing PV panels produced a 65 percent reduction in peak, versus south-facing panels, which only produced a 54 percent peak reduction.

4. You are looking to control distributed energy resources on your distribution grid.

If your utility is looking to construct or acquire a platform for controlling DERs on your distribution grid, you're not alone. Nearly one third of the utility executives who responded to Utility Dive's 2016 State of the Electric Utility Survey said they were too.

What many engaged in this exercise are discovering is this: A distributed energy resource management system (DERMS) must have a distributed architecture. Why? Because a centralized architecture will have boundaries on its size determined by the processing power, storage, bandwidth and latency of the central system.



So, for example, if a central system had to communicate with 100,000 devices needing a mere 1.0 kbps of bandwidth and 1 GB per month of storage, that system would still need some 200 MBps of continuous, sustained bidirectional bandwidth to achieve a total per data packet processing time of fewer than 10 microseconds. The storage necessary to sustain high reliability would equal approximately 1.2 petabytes per year. This is a data processing burden on the scale of a large cloud service provider, and it requires a very expensive data center. In contrast, a distributed architecture spreads this processing-storage-bandwidth burden out through the entire grid.

5. You're spending more time and resources managing your distribution grid due to solar energy.

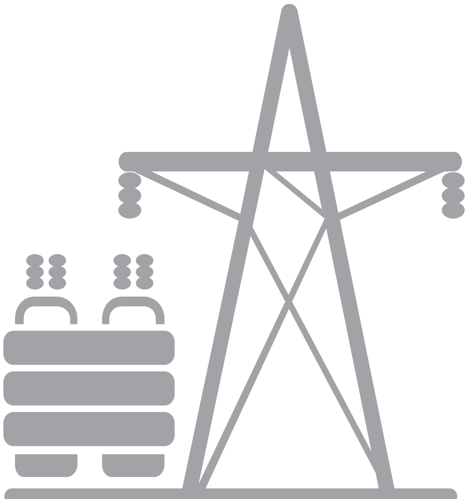
In January 2016, Southern California Edison (SCE) produced a report titled Grid Modernization: Distribution System Concept of Operations. SCE plans to spend some $2.5 billion to implement grid modernization technology on its distribution system that will help the utility accommodate DERs.

As outlined in the report, some of those distribution upgrades will include enhanced monitoring capabilities, particularly those that extend beyond the substation circuit breaker and deliver real-time situational awareness, power quality awareness and load-flow analysis data, among other things. The utility outlined extensive plans for system upgrades, such as automated notification of permanent circuit reconfigurations so that operations staff could review protection settings. Also on the list was impedance modeling technology that would represent phase, impedance, utility assets and behind-the-meter DERs on circuit maps.

The paragraph above reflects a small sampling of the kind of tools utilities will need to employ to know what's on the system and how it might behave for accurate forecasting.

Already utility staff in areas with high penetrations of interconnected rooftop solar are spending more hours doing PV penetration studies and load-flow analytics simply to make sure people can continue installing solar panels on the system. Once the customer-sited solar does interconnect, it has feeder-by-feeder and even block-by-block implications, particularly with regard to voltage excursions. Many utilities are seeing a dramatic increase in tap change operations as load-tap changers struggle to keep up with voltage fluctuations that occur with high PV penetration. That means load tap changers (LTCs) are reaching end-of-life more quickly, as they're often rated for a certain number of tap changes.

In another report titled The Impact of Local Energy Resources on SCE's Transmission and Distribution System, SCE engineers wrote about five rural feeders with some 3,500 customers attached to a 12kV substation. Commercial, industrial and agribusiness accounts drove most of the substation's demand, and a portion of these customers connected 35 PV systems with approximately 102 megawatts of capacity onto those five feeders. The result? SCE implemented feeder upgrades to the tune of $1.3 million, mostly to mitigate voltage and overloading problems.



6. You have overloaded feeders and substations.

There are multiple ways PV systems can contribute to overloading on the distribution system. One is "masked load," which is load that is hidden from upstream sources because it's being served by the local PV generator. Any load attached to a circuit is "native load," but it won't be the same as measured load when PV is on the system because measured load is the sum of native load plus PV output. If system planning decisions are made on measured load instead of native load calculations, they may be missing that masked load, so overloads can result, especially when PV stops generating suddenly.

Masked load also can leave faults uncleared. For example, suppose a big solar site is putting power into the grid when a fault occurs down the line, further away from the substation. In this case, let's say a car hits a pole and knocks it down. But the solar system continues providing power to feed the fault, creating a circumstance where the substation does not see the fault at all. That's how the fault remains uncleared, resulting in unsafe conditions.

Yet another potential problem may occur when crews reenergize a circuit after an outage. Called cold load pickup, the problem is described this way in a handbook on integrating solar produced by the National Renewable Energy Lab: "The loss of load diversity coupled with inrush currents can result in feeder current levels that may be much higher than the feeder's annual peak load. This may result in overloads and low voltages if the protection system does not trip the feeder offline first."

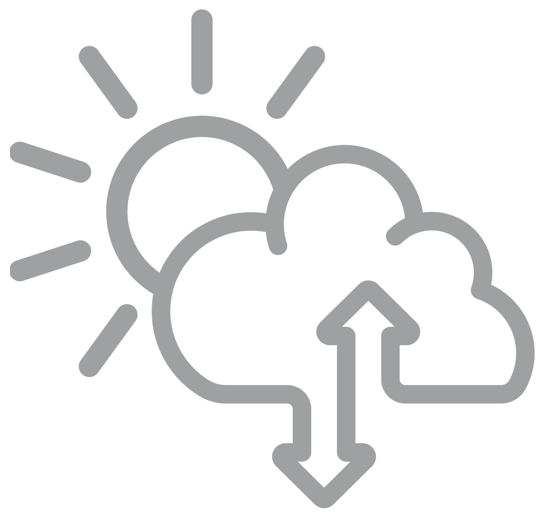
What's more, high PV penetration can make cold load pickup more volatile. That's because IEEE 1547 – the de facto interconnection standard used by most states – requires a delay before inverters can tie back to the grid after an outage. Since part of the load was masked by the PV before the outage occurred, demand on the system will be greater than anticipated in those first few minutes after service restoration.

Then, too, there's yet another reason for overloading: too much demand. Weather often is the reason, as it was in 2014. In January, a strong polar vortex froze Northeast states and bumped heating load sky high. Come September, a searing heat wave caused Los Angeles residents to set new records for power demand. Both of these events led to overload conditions.

7. You have higher calls for under-frequency load shedding, and

8. You have issues identifying which feeders to trip when under-frequency load shedding is needed.

Rapid frequency excursions are virtually unheard of in the continental U.S. Why? Because more than two-thirds of electricity that's generated now comes from fossil fuel-based plants, most of which are equipped with frequency-sensing governors that automatically adjust output to control for frequency deviation. What's more, those plants, which typically have spinning turbines weighing thousands of tons, also have tremendous inertia built into their operation. Those turbines simply don't quit spinning very quickly.



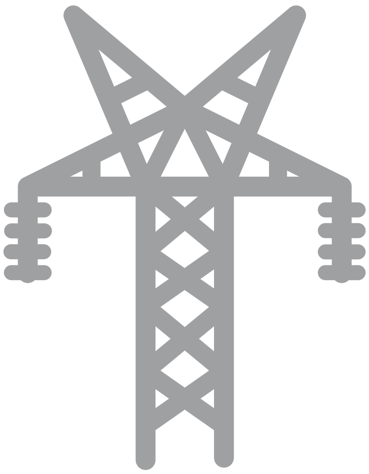
But, the California Independent System Operator (CAISO) has calculated that if the state reaches its goal of 33 percent renewable generation by 2020, as much as 60 percent of energy could come from renewables in times of low load and high renewable generation. That, CAISO says, could leave the grid vulnerable to frequency decline if a large conventional generator or transmission asset goes suddenly goes offline.

Why? Because that tremendous inertia built into the thousands and thousands of tons of spinning mass in traditional coal-fired turbines doesn't exist in solar generators. It's that inertia that helps keep frequency relatively constant in the contiguous U.S. states versus places like Hawaii, where high levels of renewable generation and the closed nature of island networks leave them susceptible to under-frequency problems. Under those conditions, frequency can drop quickly when a generation source lowers output or suddenly goes offline.

Hawaiian Electric Company (HECO) has been investing in Line Under-Frequency (LUF) automatic protection devices for more than 10 years. These are locally-sited, load-management tools that automatically address a four-hertz frequency decline that occurs in three or four cycles, or mere fractions of a second.

Automated under-frequency load shedding (UFLS) typically occurs at substations and trips off many feeders immediately when frequency falls below a setpoint. UFLS can actually make things worse by tripping off a feeder that has lots of solar generation on it that could help shore up the lagging frequency. That can easily happen when system operators lack visibility onto the feeder and awareness of the DERs connected to it.

Furthermore, under-frequency load shedding may become an issue for more utilities in the future. That's because lack of inertia in the system contributes to it, and our entire power system may see inertia dwindle. According to researchers at the Rocky Mountain Institute, "a total of 46,000 MW of coal generation is on track to close in the ten years spanning 2012-2022. As coal assets are decommissioned, solar PV is likely to step in and cover a large share of the capacity need."



9. You have increasingly unbalanced phases on the distribution network.

With larger, three-phase loads, solar installers are supposed to make sure the solar panels are fully balanced on the system so that equal or near-equal numbers of panels are connected to each of the three phases serving the premises. Are the panels connected that way? Rarely.

Instead, the PV installers often connect all the solar panels on one phase only, which means utilities end up having one phase swinging out of balance with other phases on the feeder. Since this usually happens on commercial loads, the impact is amplified. Often, there's a drop in voltage on the overloaded phase. Such unbalance affects the entire feeder, contributing to energy loss due to line impedance and increased reactive power.

10. You are cautious about using customer-sited inverters for VAR and voltage control.

Technically, putting smart inverters on PV installations could correct for both voltage and frequency problems. After all, these devices can collect data about voltage, volt amperes reactive (VARs) and frequency at their terminals. Then, they can impact voltage and frequency. For voltage control, smart inverters can generate or absorb VARs to raise or lower voltage. If frequency drops, the inverters can increase real power. And, these devices can take these actions autonomously to address grid-stability threats.

That's the potential. In reality, even when smart inverters are on the feeder, many utility professionals don't use these capabilities. For the most part, this is because most states and utilities are following IEEE 1547 as an interconnection standard, and it mandates that DERs disconnect within short timeframes in the event of abnormal voltage and frequency.

Below is a chart showing the standard states at which DERs must cease to energize. The clearing time includes both relay time and breaker time, so DERs must trip before the specified time is reached. More liberal guidelines have been recommended by a number of organizations, including the North American Electric Reliability Corporation. But, completing the standards ratification process could take until 2018.

Voltage and Frequency Disconnect Requirement Contained in Existing IEEE Standard 1547

Volatage Range (% Nominal)	Max. Clearing Time (sec)*	Frequency Range (Hz)	Max. Clearing Time (sec)
V < 50%	0.16	f < 60.5	0.16
50% ≤ V < 88%	1.0	f < 57.0*	0.16
110% < V < 120%	1.0	59.8 < f < 57.0**	Adjustable between 0.16 and 300
V ≥ 120%	0.16		

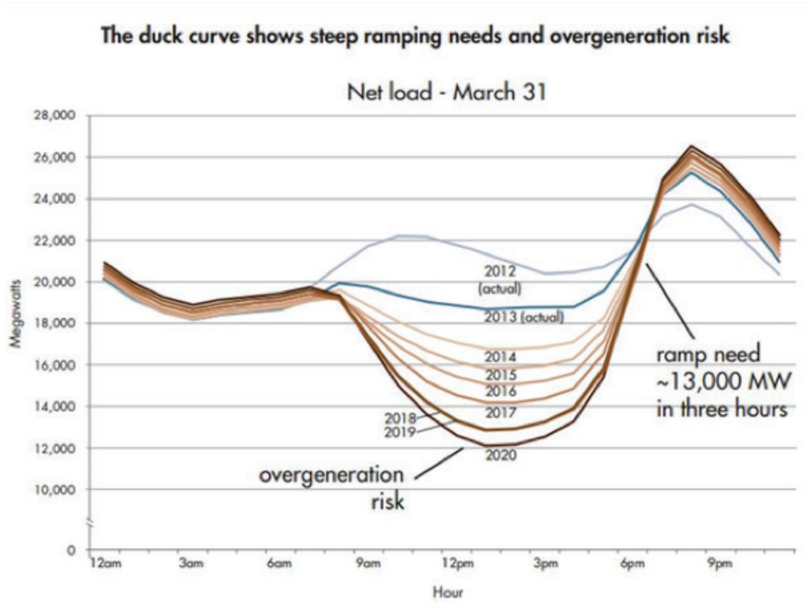
(*) Maximum clearing times for DER ≤ 30kW;
Default clearing times for DER < 30kW

(*) 59.3 Hz if DER ≤ 30 kW
(**) For DER ≥ 30kW

11. You are seeking more ways to achieve fast-ramping, flexible capacity.

If you haven't yet encountered the California Independent System Operator's infamous "Duck Curve," you probably will soon. It's a graph that shows the difference between forecasted load and expected electricity production from variable generation. In California – and many other locales – that graph takes on the shape of a duck with a belly that gets bigger and bigger as renewable penetration grows.

Why? Because most system operators currently have long-start resources that need to be online before they can support steep ramping requirements, so they have to continue producing electricity during the day, even when solar is online and producing, too. That means over-generation is likely. Over-generation can be a serious issue, requiring a utility to discharge steam or find other methods of disposing of surplus capacity. It's reflected in the belly of the duck curve, and CAISO anticipates that the problem will get bigger as even more solar connects to the grid.



At the end of the day, solar production dies down right when people are getting home and pushing up peak demand with air conditions and other loads. That's when the need for steep ramping occurs. It shows up in the neck of the duck curve. It, too, is likely to grow with proliferation of rooftop PV.

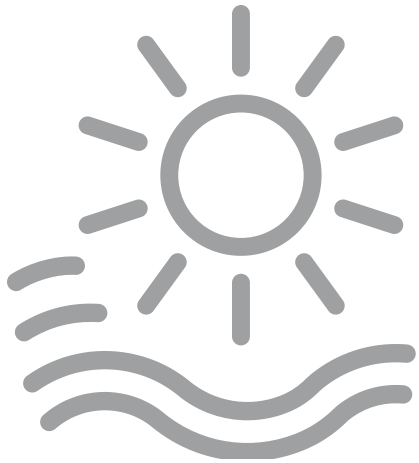
12. You are becoming increasingly concerned about maintaining a resilient and reliable distribution network.

Prediction of PV generation is tricky, but it's something that could help utilities face growing numbers of DERs on their systems. The National Renewable Energy Lab issued a paper titled Integrating Variable Renewable Energy: Challenges and Solutions. In it, you'll discover that forecast errors for renewables typically range from 3 percent to 6 percent of rated capacity one hour ahead and 6 percent to 8 percent a day ahead on a regional basis. In comparison, errors for forecasting load typically range from 1 percent to 3 percent day-ahead.

The NREL researchers also point out that, "Day-ahead forecasts can be used to make day-ahead unit commitment decisions and thus drive operational efficiency and cost savings. Short-term forecasts can be used to determine the need for a quick-start generator, demand response or other mitigating option and thus drive reliability.

Unfortunately, the authors conclude, "Solar forecasting is emerging, although not widely used today."

Add to this uncertainty some of the other problems solar can bring. They include rapid voltage problems and increased wear and tear on feeder devices like load tap changers and capacitor banks. All of these conditions could have reliability impacts.



13. You have greater than 10 percent renewable penetration on any given feeder.

After Hawaiian Electric reached 300 megawatts worth of rooftop solar generated by about 10 percent of its customers on the Island of Oahu, utility managers needed to slow down installations. The reason: Some neighborhoods had more rooftop generation than the utility's normal daytime load. "The excess energy from high amounts of PV on a neighborhood circuit can back-feed into the circuit, potentially causing reliability and power quality problems," Peter Rosegg, a spokesman for Hawaiian Electric, told reporter Martin LaMonica of GreenBiz. "This can be dangerous for utility crews and customers."

When West Monroe Partners, a Chicago-based consultancy, surveyed utility executives and regulators in 2015, researchers found that 49 percent of the utility leaders felt DERs would reach a critical tipping point and necessitate significant operational and management changes when they achieved 11 percent to 25 percent of system generation. The regulators pegged the tipping point lower. Three-quarters of them felt it would come when DERs reached 1 percent to 10 percent of system generation.

The West Monroe study also queried 2,000 utility residential customers in major markets across the U.S. Of those respondents, 49 percent were considering installing DERs for their own homes in the next two years.

14. You are having trouble identifying and remedying regions where expected service levels/power quality is not being achieved.

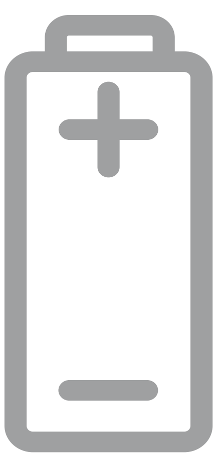
If you have a lot of transmission-level solar in your system, you also have real-time generation data, so your system operators understand what's happening at any given time. That's not the case with distribution-level or rooftop solar. Lacking visibility, system operators may not see changes in net load quickly and, if they do, they probably don't know if a rise is happening because of increasing demand or decreasing solar generation.

In addition, system operators won't see the precipitous, but very localized, drops in voltage that can occur when clouds drift over PV panels. Nor will they know if voltage fluctuations prompt PV panels to trip off in compliance with IEEE 1547.

15. You find it difficult to find enough capacity to handle increasing loads.

New York's Independent System Operator (NYISO) produced a report titled Power Trends 2014: Evolution of the Grid. In it, you'll find a great snapshot of why utilities are struggling with a mismatch between peak load growth and growth overall. The report states:

"In New York State, peak demand is forecast to grow at an annual average rate of 0.83 percent from 2014 through 2024. In contrast, overall electric energy use is forecast to grow at an average annual rate of 0.16 percent over the next decade. Simply put, the amount of power used during periods with the highest electricity demand is expected to increase at a faster rate than the amount of power used on a day-to-day basis. The pattern of peak demand growing faster than overall electricity use is occurring throughout the nation."



Now, combine that fact with this observation from the U.S. Energy Information Administration: 51 percent of all generating capacity was at least 30 years old at the end of 2010.

Furthermore, in its most recent infrastructure report card, the American Society of Civil Engineers gave our aging electric system infrastructure a D+. "Aging equipment has resulted in an increasing number of intermittent power disruptions, as well as vulnerability to cyber attacks," the ASCE report card notes.

It continues: "Significant power outages have risen from 76 in 2007 to 307 in 2011. Many transmission and distribution system outages have been attributed to system operations failures, although weather-related events have been the main cause of major electrical outages in the United States in the years 2007 to 2012 ... Reliability issues are also emerging due to the complex process of rotating in new energy sources and 'retiring' older infrastructure."

No wonder 38 percent of respondents in Utility Dive's The State of the Electric Utility 2016 survey named aging infrastructure among their most pressing challenges. And, no wonder capacity is a growing problem, particularly in peak hours.

Enbala: Relief for the Unbalance Grid

The grid challenges outlined in this paper are complex, but there is a simple way to address all of them. Symphony by Enbala™ delivers comprehensive control and optimization of grid-edge assets to support the delicate balance of electric system capacity and demand.

The platform networks and manages renewable generation, energy storage, demand response resources, substation capacitors and other grid-connected devices. Then, Symphony by Enbala monitors, forecasts, orchestrates and optimizes the operations of these asset to keep the grid balanced, renewable friendly and fully optimized, while also creating dispatchable load that can be bid into energy markets.

The end result: enhanced reliability enabled by a greater degree of grid balance.

Here's a quick look at how Enbala can relieve the 15 symptoms of an unbalanced grid.

Symphony by Enbala: Get Balanced

1. You have a backlog of solar installation approvals

The extensive visibility into DERs on any feeder and expanded situational awareness created by Enbala's platform facilitate faster and more precise PV penetration studies and load-flow analytics.

2. You have increasing numbers of voltage excursions on your distribution network.

Enbala's distributed architecture and control technology allows for localized mitigation of block-by-block or feeder-by-feeder voltage excursions.

3. You are looking to install, own and operate distributed energy resources.

Symphony by Enbala brings you detailed awareness of the conditions of DERs on your grid every two seconds. It also allows you to control DERs through automation routines or centralized dispatch, whichever best fits your needs and circumstances.

4. You are looking to control distributed energy resources on your distribution grid.

See #3, above.

5. You're spending more time and resources managing your distribution grid due to solar energy.

With Symphony by Enbala, you'll dramatically increase your situational awareness of DERs connected to your grid. The platform also provides highly accurate forecasting capabilities.

6. You have overloaded feeders and substations.

Symphony by Enbala turns all of your connected assets into one dispatchable resource that you can precisely control.

7. You have higher calls for under-frequency load shedding, *and*

8. You have issues identifying which feeders to trip when under-frequency load shedding is needed.

While NERC rules prevent power system operators from tripping off DERs to address under-frequency conditions remotely, Symphony by Enbala allows for localized control with very low latency, thereby allowing system operators a greater degree of management capability. In addition, the system allows you to know which feeders have the lowest penetrations of DERs. That way, you can trip off those feeders with lower PV penetration levels and not inadvertently knock out the distributed generation that could help your system recover its balance.

9. You have increasingly unbalanced phases on the distribution network.

Enbala's high speed data collection touches all phases and reveals where unbalance exists so you can send crews to correct it.

10. You are cautious about using customer-sited inverters for VAR and voltage control.

IEEE 1547 does not allow an end user to control voltage, but utilities can do the job with the Symphony by Enbala platform. The platform also provides greater visibility into DER operations, so power providers can allow for greater degrees of voltage and frequency ride through.

11. You are seeking more ways to achieve fast-ramping, flexible capacity.

The dispatchable resource you gain with Symphony by Enbala operates rapidly enough to deliver renewable firming, frequency regulation and more.

12. You are becoming increasingly concerned about maintaining a resilient and reliable distribution network.

Among the applications Symphony by Enbala delivers are fast demand response, contingency reserve capacity, voltage management and regulation service.

13. You have greater than 10 percent renewable penetration on any given feeder.

In one study, three-quarters of regulators surveyed thought instability could result with 10 percent or less renewable penetration on their grids. Enbala provides the visibility and control to manage renewable DER assets.

14. You are having trouble identifying and remedying regions where expected service levels/power quality is not being achieved.

Enbala provides continuous situational awareness of grid conditions and connected DERs.

15. You find it difficult to find enough capacity to handle increasing loads.

The loads connected to your grid possess tremendous process storage and potential capacity you can dispatch. Enbala modulates the way customer-connected assets operate to unlock that storage capacity with very little business cost, 100 percent efficiency, no environmental impact and no discernable disruption of your customer's business activities or site comfort.

enbala POWER NETWORKS®