Toward Bulk Power System Resilience

©ISTOCKPHOTO.COM/PICMAX13

Digital Object Identifier 10.1109/MPE.2020.2985437
Date of current version: 17 June 2020

Approaches for Regional Transmission Operators

EXTREME WEATHER, SUCH AS HURRICANES AND other storms, is the primary cause of widespread power failure in the United States. Power failures can have a significant impact on our society. With the increased frequency and intensity of these extreme weather events and future risks brought on by an evolving resource mix and the increased potential for cyber- and physical attacks, beyond reliability, the resilience of the power grid is becoming more critical. The energy industry is working to improve resilience to make the grid stronger and smarter so it can better withstand disruptive events and reduce the magnitude and duration of any power failures that do occur.

Many weather-related resilience improvements are located in the distribution systems. In this article, we focus on the regional transmission operator (RTO) perspective and provide an overview of approaches to improve bulk power system resilience. Based on our experiences at PJM Interconnection, we discuss improvements and challenges to creating a more resilient system, looking at aspects of operations, infrastructure planning, markets, and cyber- and physical security.

System and Market Overview

PJM is responsible for ensuring reliable power system operation and efficient electricity market operation in all or part of 13 states and Washington, D.C.. It is also responsible for the regional planning processes for generation and transmission expansion to ensure future system reliability. The resilience of this region's bulk power system, which is part of the Eastern Interconnection of North America, has broad societal impact, producing approximately 21% of the U.S. gross domestic product.

This system has more than 84,000 mi (135,000 km) of transmission lines and 1,440-plus generation resources, with a peak load greater than 165,000 MW. The system's reliability is bolstered by the largest competitive wholesale electricity market in the world, with more than 1,040 member companies and US$50 billion in billing in 2018. The market products include energy, capacity, ancillary services (such as reserves and regulation), and financial transmission rights.

The total installed capacity of the system is greater than 186,000 MW, of which natural gas resources account for roughly 40% (over 74,000 MW). Natural gas is becoming the dominant fuel for our generation fleet on the basis of installed capacity. We estimate that in three to four years, natural gas will make up approximately half of the committed capacity (Figure 1). The resource mix also includes more than 10,000 MW of demand response (DR) resources.

Enhancing Bulk Power System Resilience

At PJM, resilience means the ability of the system to withstand and reduce the magnitude or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, or rapidly recover from those incidents. Such high-impact, low-frequency threats include extreme weather, electromagnetic and geomagnetic disturbances, cyber- and physical attacks, fuel security, and the loss of interdependent infrastructure needed to maintain grid reliability (e.g., telecommunications).

All grid operators already comply with established North American Electric Reliability Corporation (NERC), regional, and transmission owner reliability standards. Resilience moves beyond reliability, addressing the challenges and emerging risks that existing reliability standards do not fully capture, including

- ✔ maintaining reliability in the face of disastrous events
- ✔ evaluating threats and protecting essential systems based on assessed risks
- ✔ improving grid flexibility and control to adapt efficiently and quickly to postevent conditions
- ✔ slowing disruptive events and mitigating their impacts as well as quickly recovering essential functions.

By Hong Chen, Frederick S. (Stu) Bresler III, Michael E. Bryson, Kenneth Seiler, and Jonathon Monken

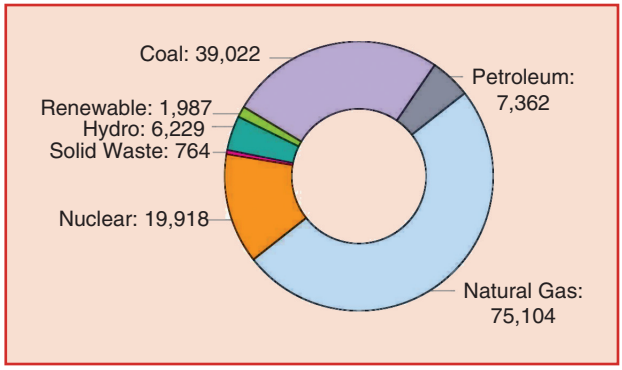

figure 1. Cleared capacity for the 2021–2022 delivery year (in megawatts).

Operations Aspect

Some of the operational aspects of resilience include conducting stressed-system studies to model operations under extreme weather conditions, improving system restoration processes and plans, using synchrophasor data and systems to improve operational resilience, and mitigating geomagnetic disturbances.

Fuel Security Analysis

New combined-cycle gas units are being constructed at the same capacity levels as nuclear and supercritical coal units. In some areas, this buildout has the potential to introduce common-mode failure risks, due either to competition with the residential heating load or failures of delivery systems that serve multiple units. As generation replacement continues to favor natural gas, we are considering resilience measures to close gaps in the gas–electricity dependency. These include improving infrastructure contingency analyses, which consider the components of both systems simultaneously, and ensuring that the electric system has fuel security as the fuel mix continues to change. Fuel security could include elements such as longer-term DR, renewables coupled with storage, distributed energy resources (DERs), multiple or backup fuel sources, and onsite fuel storage.

Recently, several industry groups, including NERC and some independent system operators (ISOs), have conducted analyses focused on vulnerabilities in the fuel supply, which is also called fuel security. Planned retirements of generating plants, an evolving generation fleet, and emerging risks from cyber- and physical attacks highlight the need to identify vulnerabilities in the fuel supply chain. An example of such vulnerability is the potential risk of increased dependence on natural gas generation and the pipelines that support those generators. Pinpointing related concerns will enable the industry to establish criteria to value energy security and develop solutions to address identified problems.

PJM conducted a fuel security analysis to test the grid's ability to endure high-impact, long-term disruptions to generators' fuel supplies. The study looked five years into the future, analyzing more than 300 scenarios with varied elements, such as extended periods of cold weather, customer demand, fuel availability, refueling frequency for secondary fuels, generator forced-outage rates, generator retirements and replacements, and pipeline disruptions (Figure 2). The study used winter scenarios because that is when the natural gas supply is strained by competition with commercial and home heating needs. The results indicated that, even in an extreme scenario, the system would still remain reliable and fuel secure during an extended period of severe weather combined with high customer demand and a fuel supply disruption. We did see issues in the extreme retirement cases under extraordinary winter

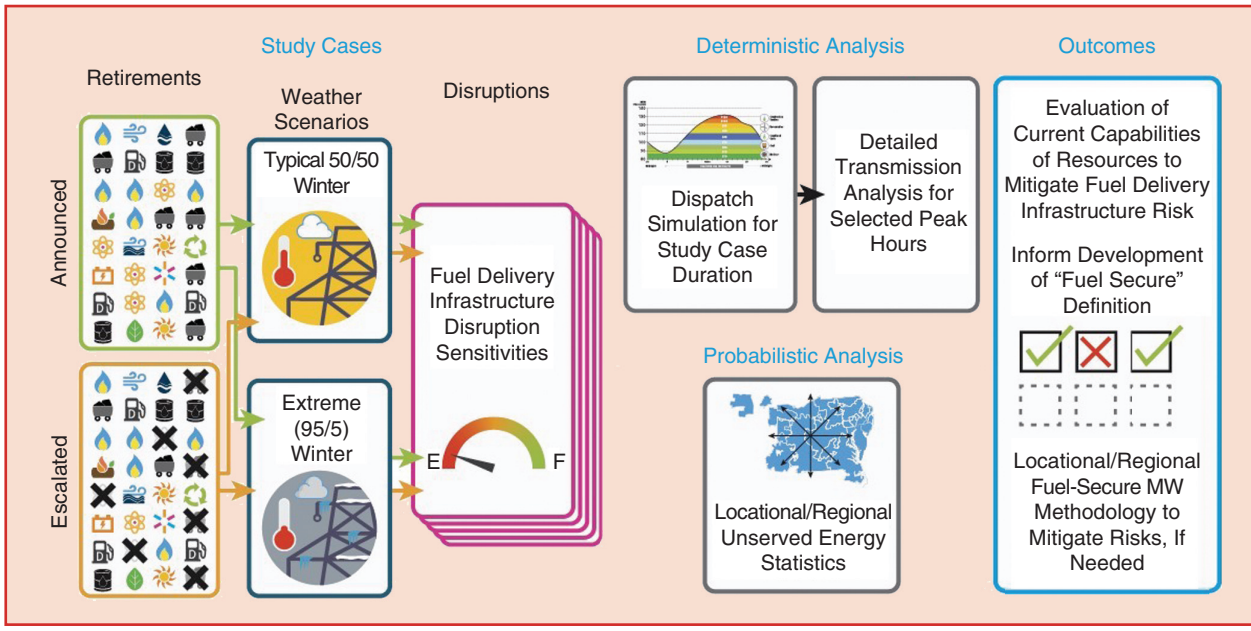

figure 2. A fuel security analysis approach overview.

load scenarios. Based on these results, work with stakeholders has begun to develop appropriate market and operational changes to address any future fuel security risks.

System Restoration Process

System restoration and black-start processes have been a staple of the utility industry for years. These processes are based on fundamental plans, training, system design, and drills. Many of these plans are partially exercised during storm restoration events. Historically, very few events have required the full execution of utility restoration plans or black-start protocols. The industry must continue to review and advance the system restoration process to address additional scenarios, such as black-sky events, that exceed the impacts of previous disruptions. Most system restoration plans assume that the transmission network is relatively intact and just needs to be restarted. If there is significant damage to the transmission infrastructure, system restoration plans may not accomplish their intended purpose. We are reviewing current system restoration processes to look for opportunities to revise them to accommodate the potential for major damage to infrastructure and recovery efforts that last weeks, rather than days.

These improvements may include the consideration of redundant transmission infrastructure and the development of planning and operational tools designed to manage our dependence on other infrastructure sectors, such as fuel supplies and delivery, water, and telecommunications. In cooperation with the Electric Power Research Institute and the Electric Subsector Coordinating Council Research and Development Committee, we are evaluating resilient communication technologies that are better able to survive a disruption than commercial tools and less dependent on potentially vulnerable telecommunications systems. Such technology would enable enough connectivity to perform tasks related to black starts and system restoration, even if traditional communications were impacted.

Synchrophasor/Phasor Measurement Unit Utilization

With the aid of a US$14 million U.S. Department of Energy stimulus grant, PJM and its member transmission owners have installed more than 400 phasor measurement units (PMUs), or synchrophasors, in more than 120-plus substations in 10 states (Figure 3). PMUs offer detailed grid status reports at any given moment. Synchrophasor data has already helped to improve system reliability, especially in modeling accuracy, disturbance detection, and event analysis. Synchrophasors can also enhance operational resilience by replicating or reinforcing existing operational functions such as state estimation, area control error calculation, interconnection reliability operating limit calculation, and monitoring the thermal and voltage levels of transmission facilities. We have developed a linear state estimator tool, which uses synchrophasor data in place of supervisory control and data acquisition (SCADA) information. This tool can be used in the event of a catastrophic energy management system or SCADA failure. Further penetration of PMUs and their advanced applications, such as wide-area monitoring and control, will make the system more resilient.

Mitigating Geomagnetic Disturbances

Geomagnetic disturbances, also referred to as solar magnetic disturbances, have the potential to affect the high-voltage transmission system. Sunspots and other solar phenomena can produce large clouds of plasma (called coronal mass ejections) that can induce electric currents on Earth and high-voltage transmission lines and transformers. High levels of these ground-induced currents can cause increased reactive power consumption, harmonic currents, and the hot-spot heating of transformers, the combination of which could result in a voltage collapse and blackout. PJM has experienced some impact of such intensified solar activities during the past and developed specific operating procedures to implement when solar activity is high and could threaten system reliability. NERC also has reliability standards to mitigate the risk of instability, uncontrolled separation, and cascading outages caused by geomagnetic disturbances.

Infrastructure-Planning Aspect

For decades, planning criteria have been developed and applied to power systems around the world to ascertain the need for

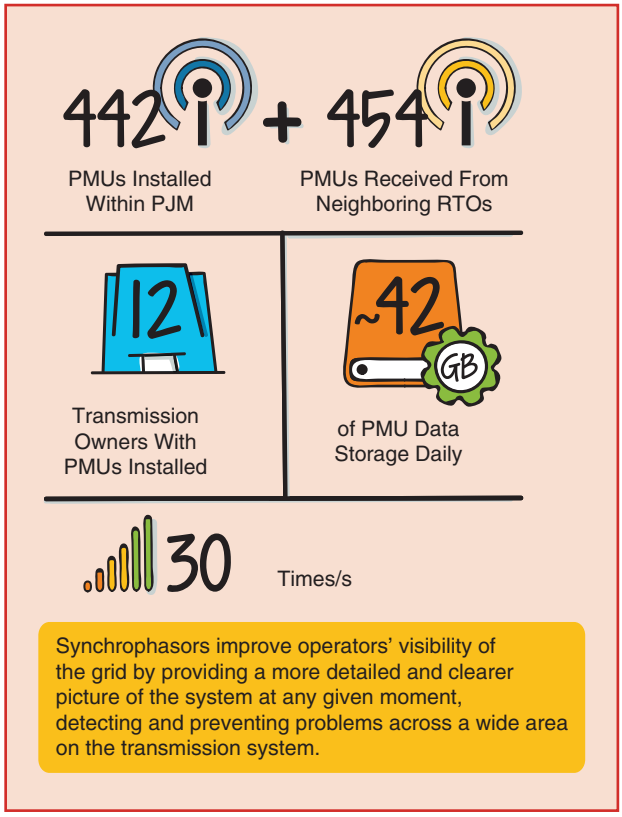

figure 3. PJM PMU statistics.

Planning criteria have been developed and applied to power systems around the world to ascertain the need for new transmission infrastructure.

new transmission infrastructure. This infrastructure provides a robust grid so that system operators can address various operating scenarios on any given day. Planners test the system under simulated stressed conditions (extreme weather, for example) to understand where reinforcements are needed to make the grid reliable. Reliability criteria are structured around likely events. NERC planning criteria require that the bulk power system be tested for contingencies, such as the loss of a transmission line, under the assumption that every other transmission facility is in service. Yet in reality, dozens of facilities are out of service on any given day. More severe, lower-probability events, such as multiple facility outages, are also tested, known as the N–1–1 test. For example, these could include the loss of two circuits on a common tower line, a fault on a circuit followed by a breaker failure, or two unrelated contingencies.

NERC standards do address resilience, to a degree. Planning standards require the examination of the impact of extreme events, such as the loss of an entire substation or a whole right-of-way because of a landslide, tornado, or fire that takes down multiple transmission lines in one corridor. Although an assessment of the impact of these events is required, reinforcement for these low-probability events is not mandatory under current NERC criteria. To achieve grid resilience, planners must also assess whether the transmission system is sufficiently reinforced to address extreme events, including physical and cybersecurity attacks and extreme weather conditions such as hurricanes.

Regional Transmission Expansion Planning

We have initiated efforts to implement regional transmission expansion planning (RTEP) process criteria and metrics to enhance grid resilience beyond what is in place today. NERC Reliability Standard CIP-014 requires transmission owners to assess and identify critical facilities that, if rendered inoperable, would result in instability, uncontrolled separation, or cascading outages. Experience suggests that developing RTEP projects in response to resilience criteria could be accomplished through three decision-making approaches:

1) *Do no harm*: The solution to an identified reliability criteria violation must not introduce other reliability issues.
2) *Leverage project opportunities*: Use projects that are already identified under reliability, market efficiency needs, or public policy requirements to solve resilience issues.
3) *Respond proactively*: Introduce new projects specifically for resilience.

Under each approach, metrics are required to assign a resilience score to every transmission facility (substation, line, and transformer) based on its criticality.

System resilience is a key consideration in the evaluation of solution alternatives so that initiatives are selected to enhance resilience as part of addressing other criteria violations or as stand-alone measures. Resilience vulnerabilities that are significant enough to warrant a transmission system enhancement could be integrated into the RTEP, for example, including building redundancy into black-start generation-cranking paths, reducing the criticality of substations through transmission line siting, and facilitating power flow diversity for areas with load congestion or high concentrations of critical restoration generating units. While the formal implementation of these transmission-planning approaches is pursued, parallel resilience initiatives continue in several other areas; for example, spare transformers need identification and cascading-event analysis tool development.

Spare Transformers

As the transmission system in the United States ages, mitigating the risk of high-voltage equipment failures becomes an increasingly important issue for transmission owners and operators. Transmission owners must anticipate procurement lead times when planning for emergencies and unexpected equipment replacements. Certain equipment, such as power transformers, can take up to 18 months from the time it is ordered until it is delivered and installed. This wait time can limit the speed of system restoration. Mitigating this requires transmission owners to develop asset management strategies, including condition assessments and monitoring equipment closely. The purpose is to maintain reliability and control costs.

To address these strategic objectives, in 2006, a probabilistic risk assessment (PRA) model was developed for managing the existing 500/230-kV transformer infrastructure. The model couples transformer conditions and asset-specific data provided by transmission asset owners with information from market analyses. This data helps estimate the annual likelihood of failure as well as the potential replacement costs and installation time for each transformer. The market analyses provide the expected congestion costs associated with the loss of each transformer. The PRA model combines failure likelihood and congestion information to determine the annual risk, in U.S. dollars, to the system from the loss of a transformer. The PRA is performed biennially to minimize transformer fleet risk exposure.

The analysis identified the need for seven new spare transformers located strategically at six substations and a congestion risk exposure of US$74 million annually that will be mitigated by the deployment of the backup transformers. The PRA also revealed that spares would increase the acceptable risk limit for transformer units in operation, extending their service lives. As of 2018, our system remains adequately mitigated with the current spare transformer unit population. System planners and transmission owners gain invaluable insight from this process. Knowing and understanding risk helps to proactively and economically address aging transformer infrastructure. An additional analysis has enabled stakeholders to plan proactive transformer replacements, spare transformer purchases, and the optimal location of spares.

Cascading-Event Analysis Tool

At its most fundamental level, a cascading tree evaluates an extreme event that encompasses a risk that may, after some number of additional cascading events, lead to a system collapse (i.e., a blackout). Major blackouts are usually caused by low-probability, high-consequence events. Since the attacks of 9/11, the power industry has taken a closer look at system contingencies that are driven not only by naturally occurring events but human-made threats as well, including

- ✔ cyberattacks
- ✔ physical attacks
- ✔ electromagnetic pulses
- ✔ the loss of interdependent systems
- ✔ severe terrestrial weather
- ✔ earthquakes
- ✔ geomagnetic disturbances.

Any such initial precipitating event could cause one or more transmission line overloads (on common rights-of-way), transformer overloads, substation losses, generator undervoltages, or load undervoltage conditions, among others.

The high-voltage transmission system is planned to be capable of withstanding a significant outage of one or a few critical pieces of equipment. However, these planning criteria do not assess what would happen to the system should a significant disruption of many pieces of equipment occur at once or in quick succession, as might be triggered by an extreme weather event or deliberate attack. Developed with a transmission owner, Dominion Virginia Power (DVP), cascading trees (Figure 4) assess the probability and consequences of cascading outages in electric systems. A cascading tree is the set of all likely cascading paths; these, in turn, describe a sequence of potential cascading outages that could reasonably be expected.

These possible outages are then classified as bounded or blown up, that is, whether the propagation of a disturbance can be confined to a certain area or if the exact extent of the cascading cannot be determined. The initial N–k event equates to the complete loss of a substation and transmission facilities. Cascading trees quantify the probability of cascading and the extent of associated consequences, leading to a natural ranking of substations. Substations and transmission facilities can then be grouped into different tiers, each having a different priority and discrete set of mitigation actions. DVP has used this methodology to identify and rank critical substations. Ideally, the best way to protect a critical substation is not to have one. However, once these critical substations are identified and prioritized, transmission upgrades are designed and integrated into the system to

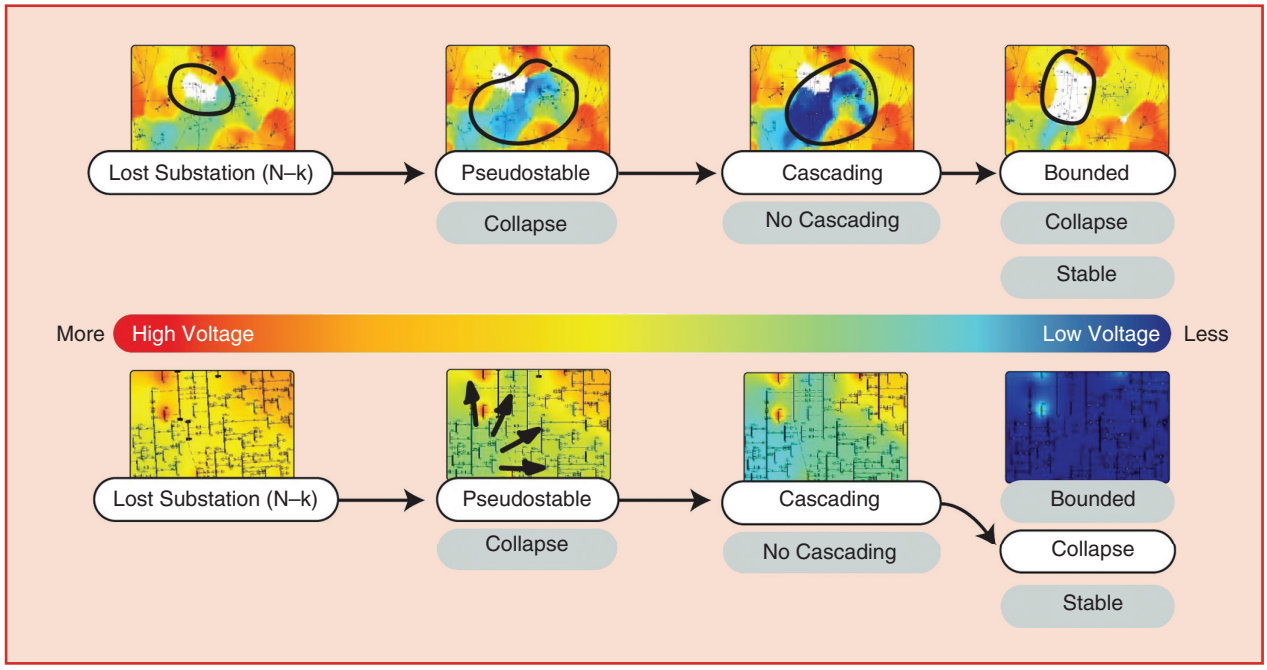

figure 4. Example images from the cascading-tree assessment.

Market prices should incentivize and provide appropriate compensation to resources for the value of the services they provide to ensure grid reliability and resilience.

make the facilities less critical and remove them from the list of critical infrastructure.

We are currently developing a resilience metric to complement and enhance the planning process, which has traditionally been very deterministic and focused on reliability and efficiency. The intent is to incorporate cascading trees into the planning processes as a consideration to make the bulk power system more robust and resilient to the potential naturally occurring and man-made extreme events.

Market Aspect

Competitive markets help improve the resilience of the wholesale electricity supply through incentives created by price signals that value the services needed to reliably plan and operate the grid. In addition, open and transparent competitive markets provide the ability for new technologies to enter and compete. The primary purpose for instituting wholesale electricity markets to begin with was to reinforce grid reliability by providing physical asset owners with the financial incentive to act in a manner that supports reliable network operation. The same approach applies to reinforcing grid resilience through markets.

Market mechanisms (i.e., market-based solutions) can be used, where appropriate, to value resilience, relying on proper price signals to incentivize resources and new solutions to help improve system resilience while harnessing the power of competition to minimize cost. The focus for the past few years has been on improving energy price formation to properly value resources based on their resilience attributes (such as fuel security) and fully integrating DERs, microgrids, DR, and storage in the markets.

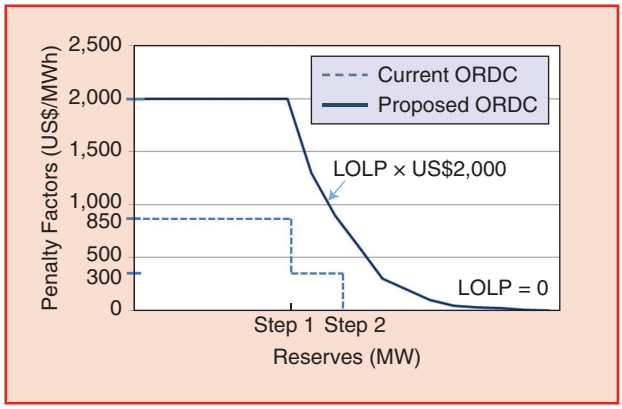

figure 5. The proposed ORDC changes. LOLP: loss-of-load probability.

Capacity Market Enhancements

The capacity market, known as the reliability pricing model (RPM), was created to ensure long-term resource adequacy at the lowest reasonable cost. By reflecting the needed quantity of reliability and resilience attributes in the capacity market, market forces can address system resilience needs, such as fuel security. During the 2014 polar vortex, PJM experienced significant generation outages of 22%. After that event, capacity performance was introduced into the capacity market to offer stronger financial incentives to generators to perform when called to operate. Overperformers are rewarded, and underperformers face penalties. The 2016–2017 capacity auction was the first to have capacity performance requirements for resources. After the right investment signals from the capacity market (which replaced nearly 27,000 MW of older generators with more than 32,000 MW of new, more efficient, and lower-emission resources), during the 30–31 January 2019 severe cold spell, the forced-outage rate was significantly reduced to 8.6% and 10.6%, respectively.

Price Formation

Market prices should incentivize and provide appropriate compensation to resources for the value of the services they provide to ensure grid reliability and resilience. Uplift payments, i.e., make-whole payments, are unavoidable under the current market construct. However, significantly high uplift indicates that prices are not reflective of what is needed to maintain grid reliability, and it reveals market inefficiency. The uplift spikes during times of system stress, such as heat waves and cold snaps, press the need for energy price formation. Reserve market enhancements have been proposed and recently filed with the Federal Energy Regulatory Commission (FERC) to

- ✔ improve reserve and energy pricing to reflect system conditions and properly value scarcity
- ✔ align reserve products in day-ahead and real-time energy markets
- ✔ use a downward-sloping operating reserve demand curve (ORDC) and increased penalty factors to ensure that all supply is used prior to a reserve shortage
- ✔ enhance locational reserve modeling to ensure reserve deliverability.

Figure 5 conceptually shows the current and proposed ORDCs, with the following enhancements:

- ✔ Increase the maximum penalty factor from US$850/MWh to US$2,000/MWh to improve scarcity pricing and replace operator intervention with market responses to higher prices at step 1, representing the minimum

reserve requirement based on the NERC reliability standard

- ✔ Use a downward-sloping tail to value reserves greater than the minimum reserve requirement at step 1, using the LOLP, and address some pricing issues created by a nearly vertical demand curve.

These changes, if approved by FERC, will result in more appropriately valued reserves in the system, especially during stressed-system conditions, and provide better incentives for resource flexibility to reliably and efficiently accommodate an ever-evolving resource mix.

Managing Natural Gas Uncertainty

For the past decade, system operators have recognized the need to improve coordination between the electric and natural gas industries. This coordination has become even more important during recent years as new natural gas combined-cycle units, wind turbines, and solar installations have become the primary new and replacement generation units throughout the system. Each energy source has introduced unique challenges to grid operations, but the natural gas units have presented issues on a larger scale. As the number of natural gas units in the system increases, network resilience is increasingly at the mercy of uncertain just-in-time fuel delivery. Gas units constitute the largest percentage of the total installed capacity: more than 74,000 MW. They account for 80% of the new capacity resources in the PJM service area. Gas uncertainty, therefore, directly affects system reliability and resilience.

As referred to previously, the 2014 polar vortex was a learning experience from a variety of angles. During that time, a significant number of natural gas units was unavailable due to the inability to procure or deliver fuel. In response, the day-ahead market timing was changed in 2016 to better harmonize the timing of the gas and electric operating day (Figure 6). This change provides more opportunity for price discovery in the natural gas markets before generation offers are due in the electricity markets. In December 2018, the deadline for market participants to submit bids and offers in the day-ahead market was extended from 10:30 a.m. to 11 a.m., better aligning day-ahead market deadlines with the most active natural gas trading period of the day. In late 2017, intraday offers were implemented so that units could submit hourly bids to the day-ahead market and make changes during the operating day to better include natural gas costs and reflect fuel availability. At the same time, gas pipeline contingencies were incorporated into system operations. The gas pipeline contingencies are triggered by certain system conditions, such as a cold/hot weather alert, capacity emergency, pipeline operational flow orders, and pipeline outages.

Integrating DERs, Storage, and DR

New technologies, such as DERs, microgrids, storage, and DR, can help make the grid more resilient.

DERs

DERs are connected at the distribution level and able to directly serve the retail load during a grid outage. Due to their resiliency attributes and economic value, more and more DERs are coming online, which makes effectively integrating them into operations and markets very important. In the current market, DERs can reduce load as behind-the-meter generation (~7,000 MW, about half of which comes from solar photovoltaics) or a resource that injects power when there is an appropriate interconnection agreement (~1,000 MW). When participating as DR, DERs are subject to existing DR rules; when injecting power into the system, DERs are modeled as generators and subject to existing generation rules. When DERs are behind-the-meter generation, they do not participate in the markets or provide data, but they do influence system conditions. Additional barriers for DER integration are being worked on with transmission owners to increase the visibility of nonwholesale DERs, improve forecasting, and enable wholesale market participation and easy switching between load and generation.

Storage

Storage has a very high reliability and resilience value to the grid, due to its siting flexibility, quick build, geographic distribution across the system, very high plant uptime, and low risk of fuel supply disruption. Storage resources are connected to transmission and distribution or sit behind the meter. Storage technologies in the system currently include pumped-storage hydroelectric plants, batteries, flywheels, electric vehicles, and residential/commercial thermal storage, such as water heaters and other technologies. PJM is the first of the U.S. ISOs/RTOs to demonstrate the ability of battery energy storage resources (ESRs) to provide frequency regulation services in a competitive market. Since 2009, the system has integrated roughly 300 MW of advanced energy storage resources. Due to its unique ability to charge and discharge, storage can participate in the markets as supply or load. Table 1 shows the different types of storage resources currently participating in the wholesale markets by type and amount. Batteries and flywheels today participate exclusively in the regulation market, providing fast regulation service.

Although ESRs were eligible to provide services in all its markets, to be compliant with FERC Order 841, PJM created an ESR participation model in December 2019 to fully recognize the physical and operational characteristics of storage resources and further remove any barriers to their participation. This model ensures that ESRs are eligible to provide all services for which they are technically capable, in a manner consistent with other resources providing the same functions: serving the load or ensuring grid reliability.

With the newly implemented model, an ESR could participate in our day-ahead and real-time energy markets under three different modes to best manage charging and discharging cycles:

- ✔ continuous mode
- ✔ charge mode
- ✔ discharge mode.

An ESR could also participate in the synchronized reserve market without an energy offer if it were physically connected to the grid and capable of providing energy within 10 min. ESRs are allowed to participate in the capacity market as well, and they may derate their capacity to meet market requirements. Similar to other resources, ESRs are dispatched and set the wholesale market clearing price as both a wholesale seller and a wholesale buyer. They are also subject to deviation charges and eligible to receive make-whole payments when moved off economic dispatch.

DR

Electricity demand, once static, is increasingly elastic and responsive to price signals, making the grid more reliable and resilient. There are more than 10,000 MW of DR in the

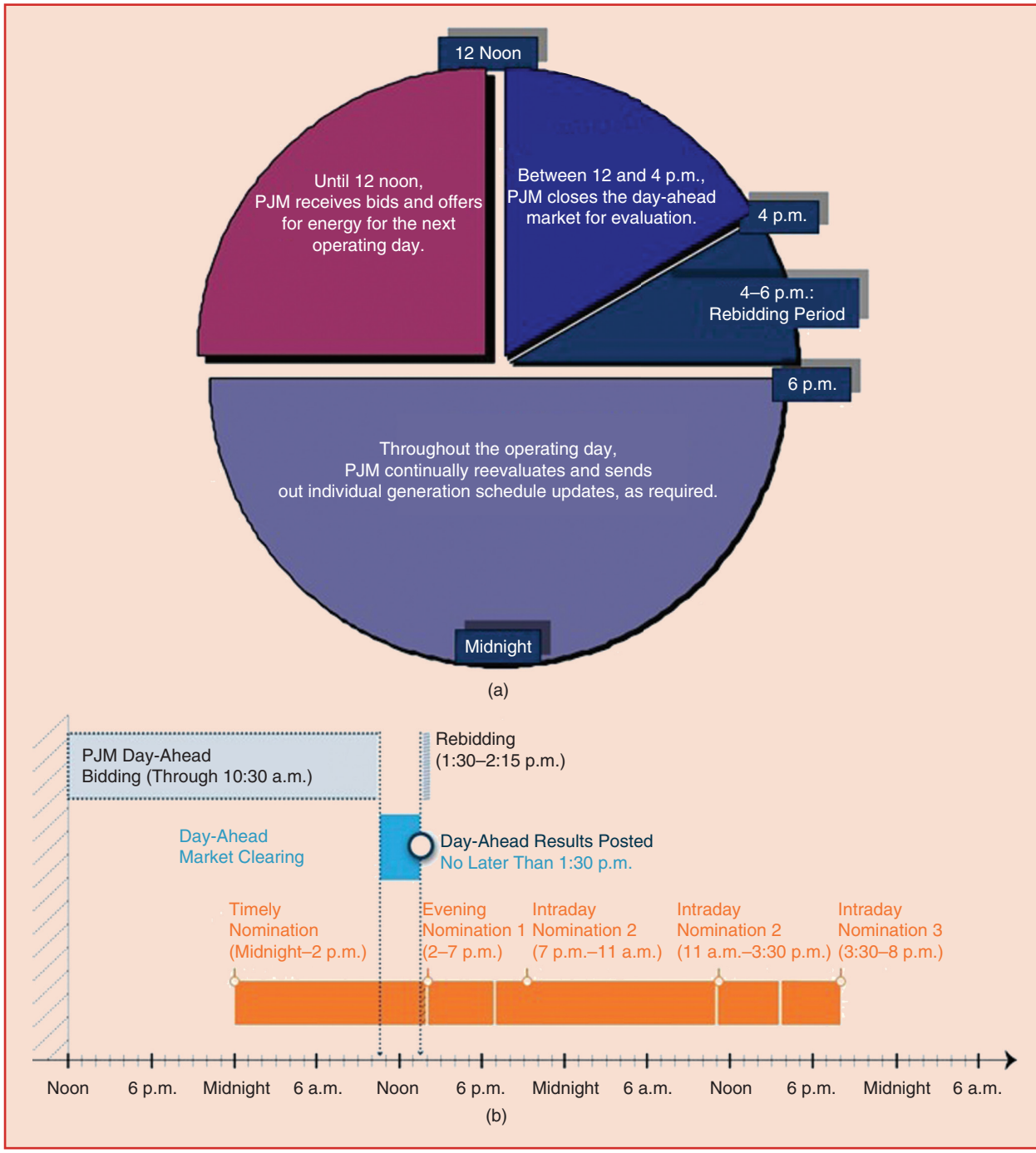

figure 6. The day-ahead market timeline (a) before and (b) after 1 April 2016.

system, the largest in the world, most of which are RPM and fixed resource requirement DR. Allowing DR to participate in all markets, i.e., capacity, reserves, and energy, significantly boosted the growth of DR (Figure 7).

table 1. Electric storage resource (ESR) participation in PJM wholesale markets.

ESR by Technology	Installed Capacity/Qualified Rating (MW)	Capacity	Energy	Ancillary Services
Pumped-storage hydro (generation)	5,537	Yes	Yes	Yes
Battery (generation)	289	No	No	Yes
Flywheel (generation)	20	No	No	Yes
Battery (demand-side resource)	14	Yes	No	Yes

Cyberphysical Security

Cyberphysical security represents an integrated approach to addressing vulnerabilities from malicious attacks on the systems, infrastructure, and assets supporting the operation of the grid and corresponding market functions. Potential exploits for the IT and operations technology environments are being identified by conducting threat assessments and crisis response and recovery exercises designed to test our capabilities to address these threats. These assessments are largely driven by the results of a comprehensive business impact analysis (BIA) in 2018, which gave insight into the tools and systems essential to maintaining the most critical functions. This analysis led to an emphasis on ensuring the availability of systems, even when confronted with hardware failures, software compromises, personnel availability, and disruptions to facilities or communications. The resulting efforts include an expansion of the IT applications with planned redundancy and site switchover capability, ensuring that the applications the BIA identified as most essential to maintaining system functionality are capable of failing over to redundant hardware at an alternate site with minimal service disruptions.

The Joint Operational Playbook document codifies processes to integrate external support personnel during a significant cyber response, paired with a more robust process of conducting cyber- and physical vulnerability assessments, called red teaming. This process enables ongoing penetration tests on systems, actively working to identify vulnerabilities in the system for remediation.

Challenges

Balance Between Resilience and Cost

The desired outcome of increasing system resilience is to reduce the impact of prolonged or significant outages. Doing so could result in a lower direct economic impact because systems would be hardened against risks and not experience as much damage. It could also reduce the indirect economic impact since the scale and duration of outages would be lessened, minimizing impacts on customers and businesses that rely on electricity. We need to determine how to achieve a balance between investments and the associated resilience benefit. If the total price equals the cost of a disaster event plus the resilience expense, how do we achieve the lowest overall expenditure? To answer this question, both the event risks and societal impact of the loss of electricity during an extended period of time need to be considered. Resilience levels/metrics must be quantified to produce criteria for the resilience

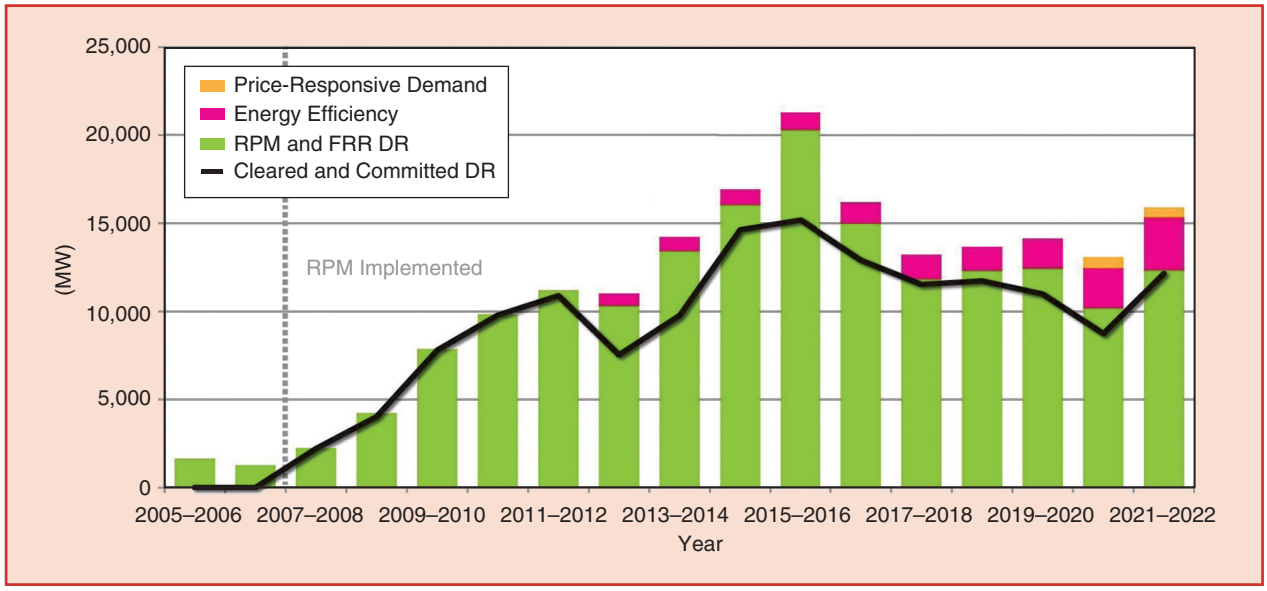

figure 7. DR in PJM markets. FRR: fixed resource requirement.

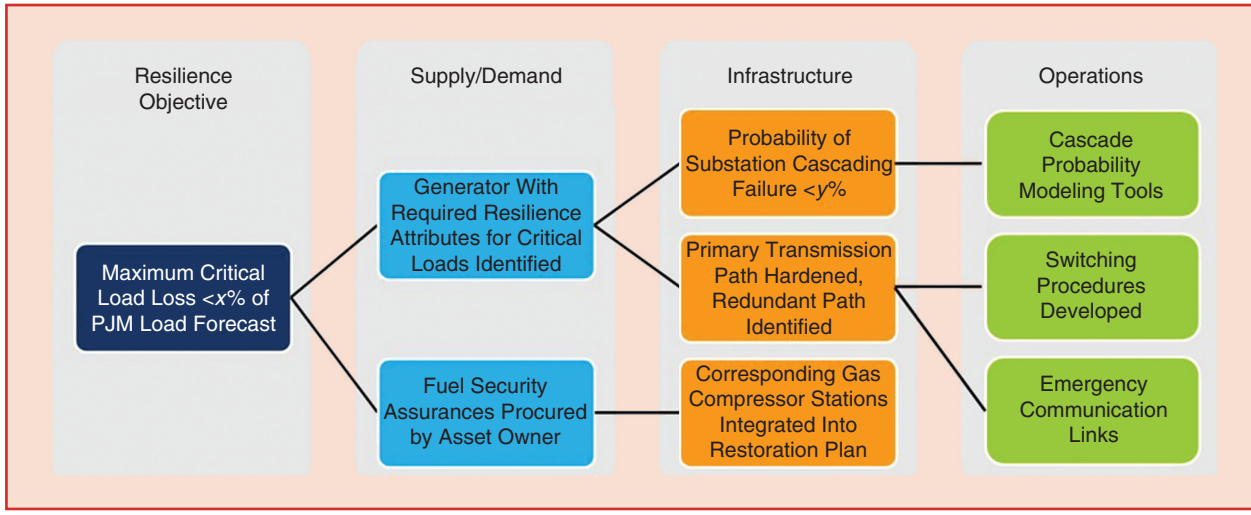

figure 8. The resilience matrix.

improvements. Stochastic analysis could provide quantitative solutions to find the most cost-effective resilience improvement.

Modeling and Jurisdiction

When working on integrating DERs, storage, and DRs, modeling details becomes debatable. Most of these resources are connected at the distribution level, and wholesale market models may not cover enough details of the distribution systems. To enable DER, storage, and DR participation, distribution-level modeling information becomes necessary, which could pose computation challenges to the related software, such as an energy management system, security-constrained unit commitment, and economic dispatch. Further, these resources cross the boundary between wholesale (federal jurisdiction) and retail (state jurisdiction). Managing jurisdiction issues is another challenge to integrating these resources as tools for system resilience.

Next Steps

Improving bulk power system resilience covers multiple dimensions of the grid ecosystem, and many activities are involved. We are working on resilience objectives, such as

- ✔ maximum total load loss: <*a*% of the system load forecast
- ✔ maximum critical load loss: <*b*% of the system load forecast
- ✔ maximum duration of outage: <*c* h
- ✔ associated resilience matrices (e.g., Figure 8).

For Further Reading

"PJM's evolving resource mix and system reliability," PJM Interconnection, Audubon, PA, Mar. 30, 2017. [Online]. Available: https://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx

"PJM cold snap performance: Dec. 28, 2017 to Jan. 7, 2018," PJM Interconnection, Audubon, PA, Feb. 26, 2018. [Online]. Available: https://www.pjm.com/-/media/library/reports-notices/weather-related/20180226-january-2018-cold-weather-event-report.ashx

"Order no. 841 compliance filing ESR markets and operations proposal," PJM Interconnection, Audubon, PA, Docket No. ER19-469-000, Dec. 3, 2018.

"Fuel security analysis: A PJM resilience initiative," PJM Interconnection, Audubon, PA, Dec. 17, 2018. [Online]. Available: https://www.pjm.com/-/media/library/reports-notices/fuel-security/2018-fuel-security-analysis.ashx

"Enhanced price formation in reserve markets of PJM Interconnection," PJM Interconnection, Audubon, PA, Docket no. ER19-1486-000 and EL19-58-000, Mar. 29, 2019.

"The benefits of the PJM transmission system," PJM Interconnection, Audubon, PA, White Paper, Apr. 16, 2019. [Online]. Available: https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf

M. Panteli, P. Mancarella, D. N. Trakas, E. Kyriakides, and N. D. Hatziargyriou, "Metrics and quantification of operational and infrastructure resilience in power systems," *IEEE Trans. Power Syst.*, vol. 32, no. 6, pp. 4732–4742, Nov. 2017. doi: 10.1109/TPWRS.2017.2664141.

Biographies

Hong Chen is with PJM Interconnection, Audubon, Pennsylvania.

Frederick S. (Stu) Bresler III is with PJM Interconnection, Audubon, Pennsylvania.

Michael E. Bryson is with PJM Interconnection, Audubon, Pennsylvania.

Kenneth Seiler is with PJM Interconnection, Audubon, Pennsylvania.

Jonathon Monken is with PJM Interconnection, Audubon, Pennsylvania.