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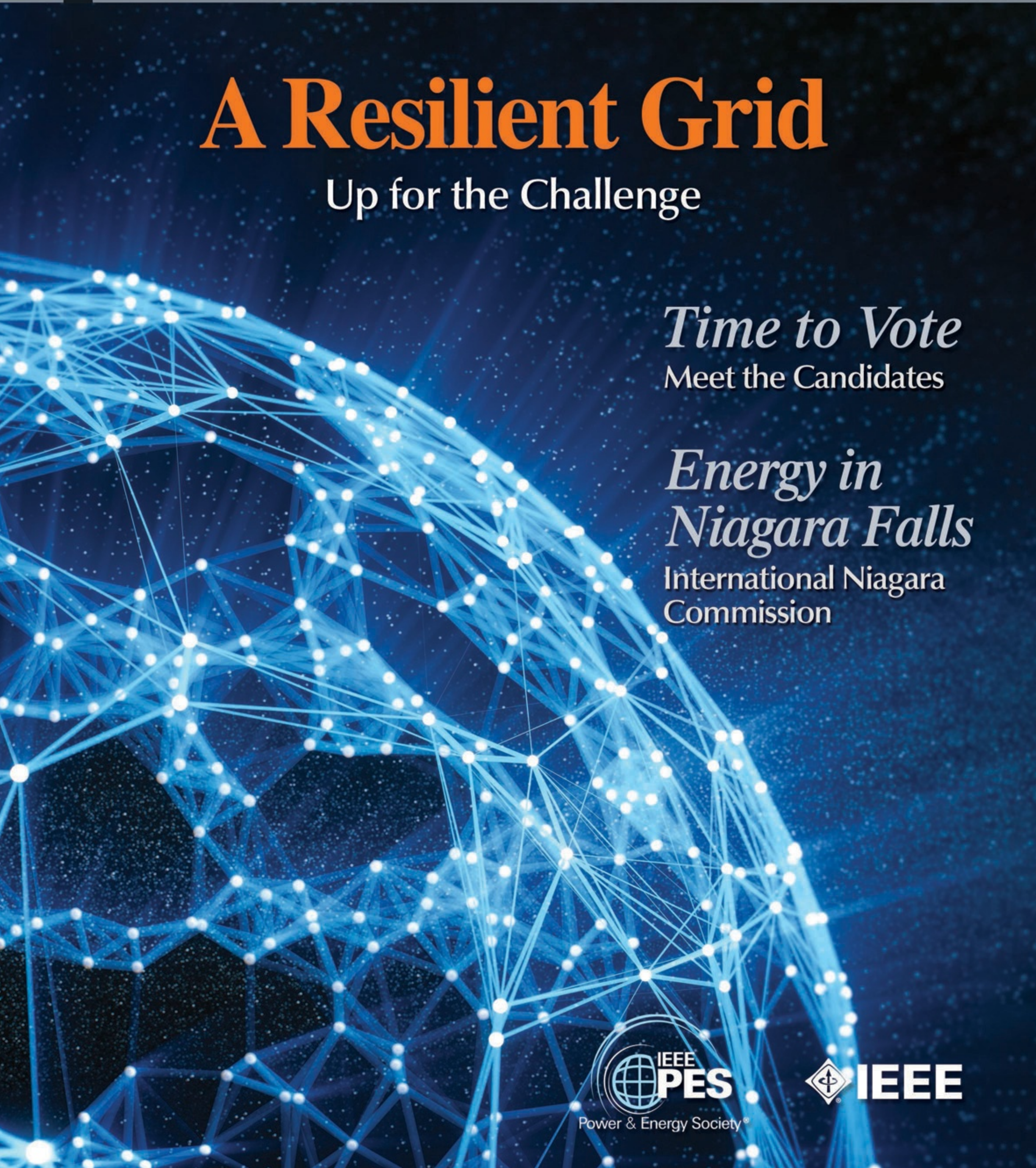
IEEE power&energy magazine

for electric power professionals



A Resilient Grid

Up for the Challenge

Time to Vote

Meet the Candidates

Energy in Niagara Falls

International Niagara Commission

IEEE PES Power & Energy Society®

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IEEE power&energy magazine
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IEEE POWER & ENERGY SOCIETY (PES)

The IEEE Power & Energy Society is an organization of IEEE members whose principal interest is the advancement of the science and practice of electric power generation, transmission, distribution, and utilization. All members of the IEEE are eligible for membership in the Society. **Mission Statement:** To be the leading provider of scientific and engineering information on electric power and energy for the betterment of society, and the preferred professional development source for our members.

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Michael Henderson

resilience in all

an overview and farewell

THIS ISSUE IS BEING ASSEMBLED in the middle of the worldwide COVID-19 virus pandemic. My heart goes out to all families who have been affected by this disaster. I wish for a rapid recovery of those who are sick and hope all stay safe and healthy. Someday, hopefully sooner rather than later, the COVID-19 nightmare will end, and IEEE Power & Energy Society (PES) activities will return to business as usual. In the interim, the IEEE volunteers and staff continue to provide extensive services to our membership, which may afford some relief to our isolation.

We are grateful to the system operators and others who provide reliable electric power to customers, which is an essential service. The COVID-19 pandemic raises special issues of isolating crews to prevent the spread of this horrific disease.

Even during more normal times, system resilience is an important factor that must be considered in the planning, design, and operation of the electric power system. Although system resilience has been more precisely defined in many ways, it can be thought of as the ability of the system to resist, adapt to, and recover from disruptions. The concept of resilience includes low-probability, high-risk events, including natural and human-made disasters. Unfortunately, the frequency and severity of these extreme events seem to be increasing as a result of climate change and the system's growing dependence on key cyber and physical assets.

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Resilience issues can be addressed through improved means of planning, engineering, and operating the power system. It involves much more than the traditional *N*–1 and *N*–1–1 normal criteria analysis typically used for planning and operating the system. New means of quantifying the system risk from extreme events can improve the system's ability to withstand and recover from these events.

In This Issue

Thanks to Guest Editor Jianhui Wang and his team of outstanding authors, this issue of *IEEE Power & Energy Magazine* discusses system resilience. This issue shares experience worldwide that identifies resilience issues, lessons learned, and innovative solutions. As described in the "Guest Editorial" column, five excellent articles provide key insights into system resilience:

- ✔ *An independent system operator/regional transmission organization perspective on resilience*: The article discusses the importance of fuel security in addition to long-term infrastructure planning, markets, and cyberphysical security. Some of the next steps being taken to address these issues are summarized.
- ✔ *The opportunities for improving system restoration through the use of distributed generation (DG)*: The successful implementation of DG requires observability and controllability, coordination with the transmission system operator, command and control, and regulatory support. Analysis tools and training are also vital to utilizing DG.
- ✔ *A means of focusing on high-impact, low-frequency events and examining the temporal nature of resilience*: The authors present a probabilistic risk-based framework for identifying network improvements. They discuss their experience with the operation and planning of the Chilean power system as a practical case study.
- ✔ *A discussion of blackouts, restoration, islanding, and the metrics that should be used in power system operations and planning to assess system resiliency*: The effects of information and communication technologies on the power system

and key infrastructure need to be considered. The article also discusses islanding strategies where DG can play a crucial role in system restoration.

- ✔ *A new measure for quantifying system resiliency by identifying vulnerability and criticality for identifying key facilities as a function of system stress*: An analysis of the U.S. Western Interconnection system demonstrates the usefulness of the proposed metrics and the findings they can provide.

This issue also includes an “In My View” column that discusses the importance of diversifying restoration resources and the role that distributed energy resources such as wind, solar, and storage assets can play.

History

Past “History” columns have discussed several of the cutting-edge electric power developments that took place at the Niagara Frontier. In this month’s column, the important role played by the International Niagara Commission is discussed by author Robert D. Barnett, founder of the Niagara Society for Industrial History.

PES Update

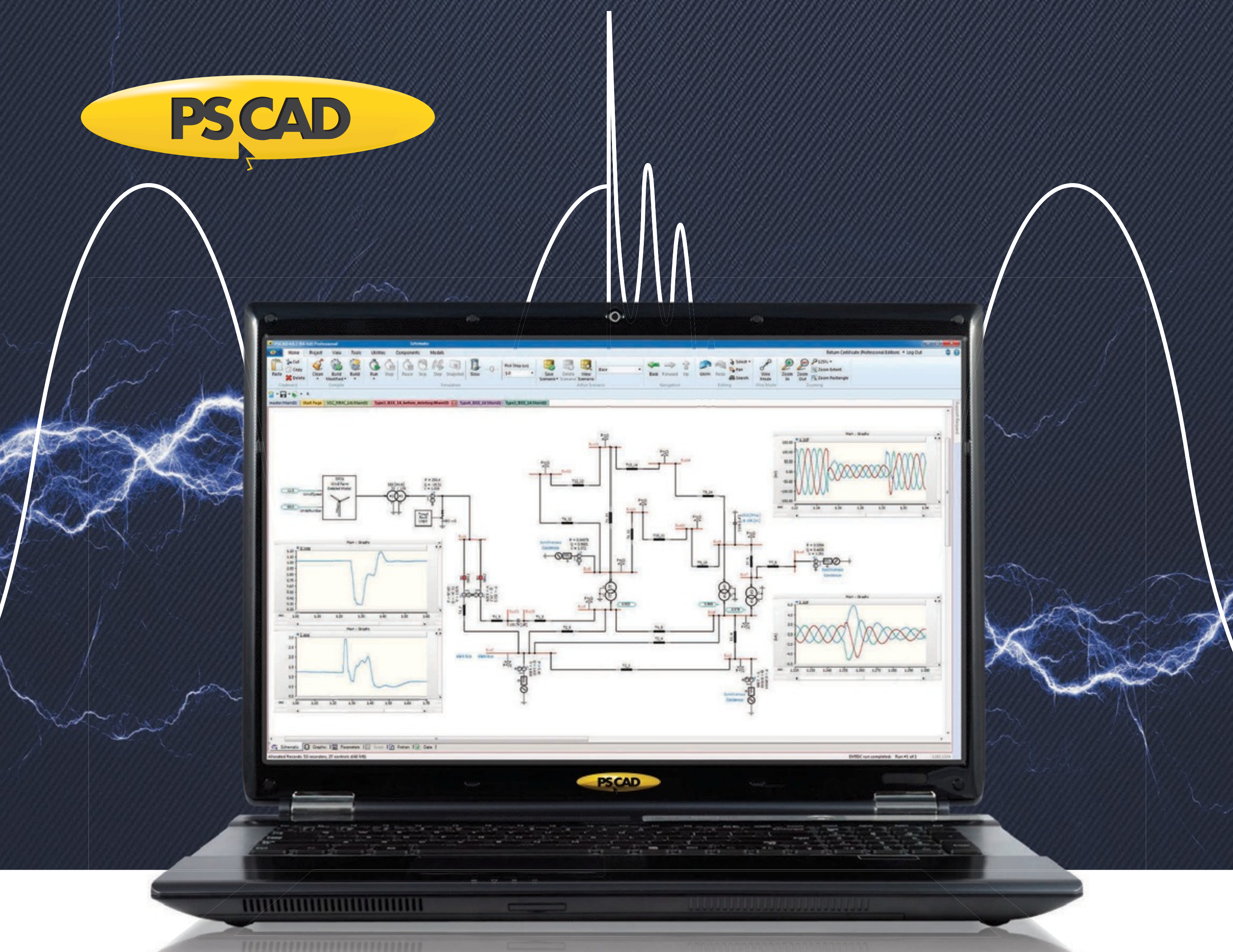
PES publications play a key role in keeping members and the wider industry up to date. In the “Leader’s Corner” column, Bikash Pal, vice president for Publications, describes several recent PES initiatives such as open access journals and the translation of the magazine into Spanish and select articles into Thai. PES has an outstanding team of editors who manage high-quality publications, as shown by the ever-increasing impact factors of our five transactions. We can be proud that editorial roles and authors across all PES publications increasingly reflect the diversity of our membership. Readers should make use of the webinars of highly downloaded and prize-winning technical papers that are available in our Society’s online resource center.

Vote!

Beginning on 17 August 2020, elections will be held for the position of IEEE Division VII delegate-elect/director-elect 2020, who will serve as IEEE Division VII delegate/director 2021–2022. (The elected individual will serve as both delegate and director.) Division VII consists of PES only. There are two candidates, both nominated by Division VII, vying for this office: Claudio Cañizares and Lalit K. Goel. To learn more about the candidates before casting your ballot, read “Society News.” Please vote! It is not only your right, it is your responsibility.

Changing of the Guard

Our industry is currently undergoing its greatest transformation since the early days of electrification. The change


PSCAD

reflects remarkable technological innovations and associated new business models in both regulated and market environments, including improvements in equipment and materials, methods and tools for planning and operating the system, renewable resource integration, demand forecasting and response, cyber and communication technologies, the growth of energy storage and microgrids, educational requirements and curricula, industry structure, rate reform, and market modernization, and a host of others.

IEEE Power & Energy Magazine seeks to inform our readership in ways (both technical and nontechnical) that help move our industry forward to a very different tomorrow. Our themed issues target our entire PES membership, which includes students, experienced engineers, academics, researchers, industry executives, attorneys, economists, and power and equipment marketers. Our magazine also includes columns that provide perspectives on the history of the industry, messages from our leadership on how PES staff and volunteers continuously improve services, opinion pieces meant to provoke interesting discussions, and updates on major society news.

It has been my privilege to serve as editor-in-chief of *IEEE Power & Energy Magazine* for the last 22 issues and previously as a member of the editorial board, guest editor, and author. A true labor of love, working on the magazine with our many contributors and IEEE Publications staff has been the most rewarding highlight of my long career and volunteer opportunities in PES. I have thoroughly enjoyed the professional and social interactions, which have greatly enriched my life. I sincerely hope our readership also finds the magazine to be as interesting and informative as I do.

It is now time to move on and turn the reins over to an as-yet-unnamed successor who will find new means of growing the magazine and serving our membership. I leave secure in the knowledge that our outstanding editorial board, incoming guest editors, and new authors will continue to improve the quality of the magazine and help PES membership meet the many challenges our industry faces worldwide.

Thanks

Thanks to the IEEE PES leadership who showed faith in me as editor-in-chief and continue to support the magazine. Our success remains a tribute to many wonderful dedicated people, all of whom are impossible to name but include the editorial board members

(continued on p. 18)

share your thoughts

send comments to j.paserba@ieee.org

READERS ARE ENCOURAGED TO share their views on issues affecting the electric power engineering profession. Send your letters to John Paserba: j.paserba@ieee.org. Letters may be edited for publication.

The ac Mystery

I found the article "75 Years of Drift: The Changing Meaning of Phasor" in the "History" column of the January/February 2020 issue of *IEEE Power & Energy Magazine* (vol. 18, no. 1) very interesting. It's good to see a history article that deals primarily with concepts. I'd like to mention the possibility that Steinmetz was concerned with the fact that using a phasor carries with it the implication that the frequency of ac is constant. In the days before generators were driven by turbines, this was not the case. Because the reciprocating steam engine was the most common prime mover, the angular velocity of the alternator's rotor changed throughout the cycle. AC was a great mystery. It did not appear to follow the rules that governed dc. Capacitive and inductive reactance were not well understood—in many cases, not understood at all. P.N. Nunn, one of the ac pioneers who designed and installed the Telluride project, said, "In 1890, ac was just plain freak; it did not follow Ohm's law and 'clogged' itself in its circuits."

In any case, the big deal in those days was the lack of any simple ac-calculating techniques. This may be Steinmetz's most important gift to electrical engineering. Before his development of the complex analysis of electric circuits, one was faced with solving the general equation for electric circuits, which we now associate with dc circuits only. This was the only means available. For more information, see *Alternating Current*, by Frederick Bedell and Albert Crehore (New York: W.J. Johnston Co., 1893, pp. 83 and 160).

—*Bob Barnett*

One was faced with solving the general equation for electric circuits, which we now associate with dc circuits only.

Author's Response

First, I'd like to thank you for your interest in my article and for sharing your thoughts. You are quite correct about the fact that the underlying concept in these mathematical representations demands a constant frequency. Most of us would be quite unable (or perhaps unwilling) to try to model a system in which the effect of the pulsations of the reciprocating steam engine appeared in the generated power.

I wonder if Bedell and Crehore were the first to apply what we would call the phasor representation to our problem. The generation of a sine function in their book is clearly based on the same method described by Thomson and Tait (my article cited the book as it was published in 1867, though the method may have been known earlier). But that work gives no hint of the method's use in electric power.

I note that Bedell and Crehore were usually very careful to say that the equation "represents" some physical quantity. As I am sure you are aware, that makes conceptual sense. To write that a phasor measurement unit (PMU) "measures a phasor" does not make sense. A PMU measures a signal that we assume is well represented by a sinusoid, and we then express that sinusoid in phasor notation.

I fear that as our grid gets smarter and we get further removed from the awareness that we are forcing the representation to be sinusoidal, we will encounter problems. If the signal that we feed to our PMU is not well represented by a sinusoid, we may very well get a result that has little or no meaning. And we may not even know it. This is a matter that goes beyond the question of constant frequency.

—*Harold Kirkham*

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Bikash Pal

successful publications

where the best intentions of all meet

THE VALUE OF DISSEMINATING the right information at the right time could not be more appreciated while we fight COVID-19 for our survival. The early statistical evidence suggests that communicating the correct message well in time has had a positive impact by reducing the loss of human life worldwide. Our 2020 success with IEEE Power & Energy Society (PES) publications resulted from a series of new initiatives we took in 2018 and 2019, which was the year of open access (OA) initiatives. The IEEE developed a strategy to seize the leadership in the OA publication space in the electrical and electronic engineering (EEE) discipline. Besides continuing with hybrid journals, a Society-based OA journal and a section in *IEEE Access* were proposed. Unlike most IEEE Societies and Councils, PES went with the option for both a new Society journal and a PES section in *IEEE Access*. 2020 is the year for PES to build on these two initiatives. As of 21 March, the PES section in *IEEE Access* has published 36 out of 285 submissions. There are 10 dedicated editors for this section, three of whom are female. I would like to thank them for doing a brilliant job of peer review for articles submitted to this section. Please consider submitting technical articles there.

IEEE Power and Energy Technology Systems Journal (*PETS-J*) has been succeeded by *IEEE OA Journal of Power and Energy* (*OAJPE*), beginning in January 2020. It is now led by Fran Li, University of Tennessee. The journal also has a promotion and outreach editor, João Catalão, University of Porto. Both are extremely helpful and approachable volunteers. It is a single-volume-only (one volume and issue a year) publication and has already published 15 papers. I am very confident that it will receive a good impact factor three years from now. I encourage you to submit papers to this journal.

The IEEE developed a strategy to seize the leadership in the OA publication space.

In 2019, we launched an initiative to translate selected published articles from *IEEE Power & Energy Magazine* into Thai and distribute them online to our members in Thailand through our local Chapter. The first article, "How Electric Vehicles and the Grid Work Together," is available. The local committee is chaired by Weerakorn Ongsakul, Asian Institute of Technology, and championed by Praditpong Suksirithawornkul. Please contact them or keep an eye on this space for some more to come. Our Spanish version of *IEEE Power & Energy Magazine* has been doing extremely well under the leadership of Enrique Tejera. This initiative has been well received by our members from Latin America (Region 9) for providing the opportunity to have the latest information and developments in their own language. PES is the IEEE Society with the most presence in Region 9.

By now, perhaps you have had the time to take a look at the 2020 transmission and distribution (T&D) special issue of the magazine. There are eight articles focusing on research, development, and deployment activities in digital simulation technology. Sadly, the 2020 T&D Conference and Exhibition is postponed until October of this year because of the COVID-19 pandemic. However, I strongly believe that, in addition to the more than 14,000 anticipated participants for this flagship show of the IEEE, all our members will benefit from the contents of the issue.

The PES currently sponsors five transactions:

1) *IEEE Transactions on Energy Conversion (TEC)*
2) *IEEE Transactions on Power Delivery (TPWRD)*
3) *IEEE Transactions on Power Systems (TPWRS)*
4) *IEEE Transactions on Smart Grid (TSG)*
5) *IEEE Transactions on Sustainable Energy (TSE).*

All our transactions are sustaining their leadership in their respective topics, as reflected by the increased bibliometric

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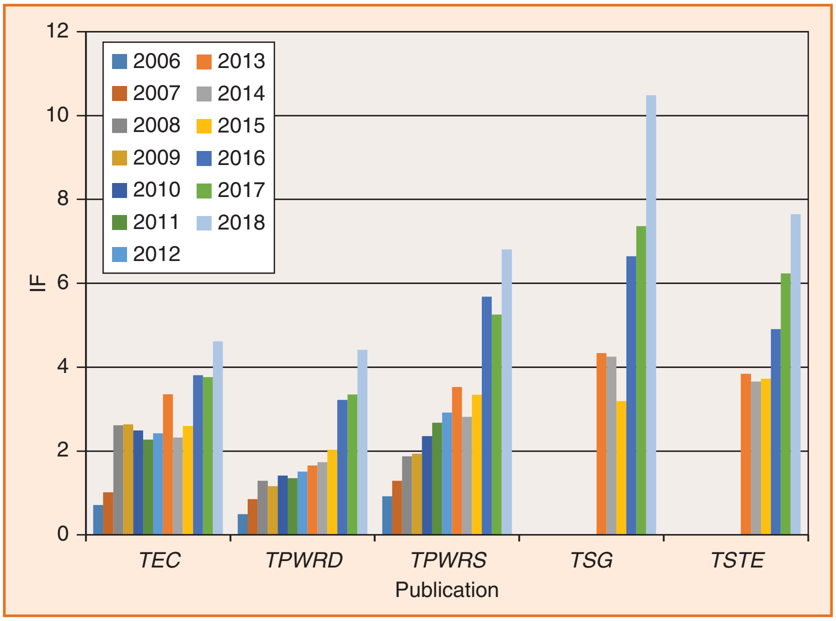

figure 1. The impact factors for PES transactions.

indices. The latest journal impact factors (IFs) (Figure 1) clearly demonstrate that fact. In the 2018 Clarivate Analytics report, out of 161 IEEE periodicals, three IEEE transactions ranked within the top 20 among all publications in the IEEE field of interest (FoI). I am very happy to share the good news that there were 52,000 more uses of PES publications in 2019 compared to 2018. This is because of the utmost trust that authors bestow on our outstanding editors and reviewers to maintain a high-quality peer-review process. Besides impact factors and citations, there are several other ways the contents of publications are valued, such as use by industry-based readers, attendance for our prize-winning article webinars, and download counts of additional materials from the data port. Our periodicals are doing extremely well in these categories, too. We are also running a webinar series on the topics of highly downloaded/prize-winning technical papers. We invite the authors of these articles to speak and archive the webinars in our Society's online resource center.

All five of our transactions have been peer reviewed by the IEEE


H2

Periodicals Review and Advisory Committee. This is an IEEE internal process conducted once every five years. All of the transactions have been appreciated for their quality, timeliness, and diversity. Our acceptance rates range between 15% and 25%. Our median time in months from submission to e-publication continues to decrease. We will continue to further improve upon our quality and timeliness.

Out of 238 editors across all PES journals, we have 37 women (15.5%). In addition, 16.7% of our editors are affiliated with industry, and 56.7% are from outside North America. We are looking for more participation on our periodical editorial boards from members of industry and women. We have been experiencing a huge shift of authorship and usage of our contents from Region 10. We are engaging with more power engineers from this Region by appointing them to our editorial boards so that our publications become even more relevant to the growth of power engineering research and development in that part of the world. To anyone from Region 10 who wishes to serve on our editorial boards, please contact our respective editors-in-chief.

In January 2020, we appointed Claudio Cañizares (University of Waterloo) as editor-in-chief of *TSG* and Francisco de Leon (New York University) as editor-in-chief of *TPWRD*. Wilsun Xu (University of Alberta) has provided outstanding service as editor-in-chief of *TPWRD*. We appreciate his visionary work for the transactions. Jianhui Wang (Southern Methodist University) offered very successful leadership to take *TSG* to a new height: it is now sixth out of 161 IEEE journals in the journal IF ranking. He retired as editor-in-chief after his term ended on 31 December 2019. Scott Sudhoff (Purdue University) has finished his term as editor-in-chief of *PETS-J*, which is now rebranded as *OAJPE*; his vision and leadership are greatly appreciated. To promote transparency and fairness in our peer-review process, we have created the position of editor-in-chief at large. We have appointed Xu to this role.

By now, you are aware that our IEEE PES General Meeting will be held as a virtual event. Please watch for the updated program, and we invite you to engage in any publication-related events. We thank you for your support and interest in our publications. We look forward to a higher level of engagement from you in our peer-reviewed periodicals. I wish everyone good health and safety during this unprecedented crisis that our world is currently facing.

Jianhui Wang

power system resilience

the golden rule of the future grid

THE ELECTRIC POWER SYSTEM is facing unprecedented challenges worldwide. Extreme events such as hurricanes, wildfires, and earthquakes have fundamentally changed the way the power grid is designed and operated. Power system planning and operation ought to go above and beyond the classical reliability indices that have governed industry practices for many decades. The fact that extreme events are of high impact and low frequency (HILF) renders traditional reliability-oriented system-enhancement measures insufficient and ineffective. Rather than focusing on routine power system component failures and outages, resilience specifically refers to the ability of a system to anticipate, absorb, react to, and recover from a rare, widespread, quickly changing, and extreme event scenario that may cause substantial and enduring damage to our society. The potential sources of disruption can also be multidimensional, ranging from naturally occurring physical damage to manmade cyberattacks.

This issue of *IEEE Power & Energy Magazine* features five articles that focus on concerns associated with power system resilience. The topics cover a broad range of areas in power system resilience with lessons learned and novel solutions across continents.

In This Issue

The first article, by Hong Chen, Frederick S. (Stu) Bresler III, Michael E. Bryson, Kenneth Seiler, and Jonathon Monken from PJM Interconnection in the United States, offers a unique perspective from a regional transmission operator (RTO). Different from the more vulnerable distribution grid, transmission systems have their own set of challenges due to the scale of the system, the wide area it covers, and the multitude of stakeholders involved. This is particularly true when an electricity market is in place to coordinate a great number of market participants and other entities to form a thorough plan before the event and carry out an efficient response when the event takes place.

The authors highlight these issues by first looking into the operations aspects of bulk power system resilience, among which fuel security analysis stands out as an often-overlooked component of the overall resilience improvement portfolio. Fuel security requires a long-term vision to optimize the generation mix while taking into account generation technology update and replacement (e.g., coal-fired units replaced by natural-gas-fired units), the various government policy scenarios, costs, and other considerations to minimize disruptions to fuel supply. The authors continue with other aspects including long-term infrastructure planning, markets, and cyberphysical security. The article ends with a discussion on relevant planned activities at PJM.

The second article, by Carsten Roggatz, Michael Power, and Nisheeth Singh, opens up new opportunities for power system restoration by considering distribution generation (DG) connected at the distribution networks. Using DG for restoration in addition to traditional bulk-level, black-start units signifies an important and practical technological advancement to best optimize the value that the increasing penetration of DG can add to the grid.

The authors comprehensively review the current relevant practices among European grid operators and provide a thorough discussion on the key enablers to implementing such a framework including 1) observability and controllability of DG, 2) coordination between the transmission system operator and the distribution system operator, 3) command and control, and 4) regulatory support. The authors further explore different scenarios with various DG control functionalities and penetration levels. Several restoration decision-support tools are discussed as examples for restoration training and execution.

The third article, by Rodrigo Moreno, Mathaios Panteli, Pierluigi Mancarella, Hugh Rudnick, Tomás Lagos, Alejandro Navarro, Fernando Ordoñez, and Juan Carlos Araneda, gives insights on long-term planning issues transitioning from reliability to resilience. As a result of a successful international collaborative project, which eventually led to a prestigious Newton Prize, the authors focus on two critical requirements for grid resilience enhancement: emphasis on 1) HILF events and 2) the time-varying

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nature of resilience. The authors build their case based on their extensive experience with the U.K. and Chilean power systems. By developing a novel probabilistic risk-based framework to identify resilient network-enhancement options, they are able to differentiate resilience-focused from reliability-focused network enhancement alternatives. It is of note that the authors also implement their framework in the actual operation and planning of the Chilean power system, which demonstrates the significant practical value of their work.

The fourth article, by Martin Braun, Christian Hachmann, and Jonas Haack, digs into the details of blackout, restoration, and islanding based on the concept of resilience. The authors argue that resilience-based metrics should be introduced in power system operation and planning in addition to the conventional reliability measures. The authors specifically point out the impact of digitalization on the cyber-physical resilience of the power system. With the growing penetration and deployment of information and communication technologies, the physical grid has been tightly coupled with the other relevant infrastructure. Improving power system resilience from a holistic point of view, as the authors suggest, can result in great benefits by discovering the weak spots of the system, which can be missed when analyzed in silos. A number of islanding strategies is further discussed with numerical examples to illustrate the crucial role of DG in restoration.

The last article, by Hyde M. Merrill, Md Abid Hossain, and Marc Bodson, makes an effort to quantitively measure the stress on the system that causes cascading failures. New metrics are proposed to overcome the insufficiencies of traditional metrics and find the "hidden failures" lurking in the system. The authors review many historical power grid cascading failures and conclude that the commonly used North American Electric Reliability Corporation $N-1$ reliability standards are not enough to identify grid vulnerabilities and prevent cascading failures. Leveraging network theory, two new metrics are presented, namely vulnerability and criticality. The U.S. Western Interconnection is used to demonstrate the usefulness of the proposed metrics and the findings they can provide.

In the "In My View" column, Yingchen "YC" Zhang and Juan Torres from the National Renewable Energy Laboratory shed light on using distributed energy resources (DERs) to help improve power system resilience. The authors critically point out the importance of diversifying the resources employed in grid restoration. The appropriate diversification of relevant restoration assets can greatly enhance the preparedness of the system and reduce the risk of a single point of failure. In this context, DERs including wind, solar, and storage assets are a natural fit due to their distributed locations, versatile operational modes, and locally available energy sources.

We thank all the authors for contributing to this issue of *IEEE Power & Energy Magazine*. We would also like to express our sincere gratitude to Mike Henderson, editor-in-chief, for his guidance in preparing the issue.

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from the editor *(continued from p. 8)*

who provided expert guidance and readily assisted with reviews of materials, the guest editors who assembled technical content and reviewed the issues, and the authors who provided well-written and informative pieces and patiently reflected multiple rounds of editorial review.

Certain people must be recognized. My friend and lifeline mentor Hyde Merrill assumed the role of associate editor, "History," at a time when his help was needed the most. When he was unable to continue in that role, John Paserba gladly volunteered and has expertly continued managing our most popular column and provided outstanding support to me, the magazine, and PES at large. A special note of appreciation goes to Mel Olken, who provided guidance and tutelage. The IEEE publications staff work tirelessly behind the scenes, but I want to provide a special shout-out to Geri Krolin-Taylor, who serves as our managing editor; Janet Dudar, our senior art director; and Maria Proetto, senior administrator, PES Publications. Our advertisers keep the publication on a sound financial footing, and you, dear readers, have provided feedback that has helped move the magazine forward.

I would also like to express a note of appreciation to my loving family: Robert C. Henderson, who readily provided editorial assistance; Gabby Henderson, who provided IT support; and most of all, my wife of over 38 years, Dorita, who has shown more patience and support than I could ever deserve. I look forward to spending less time in my office and more time with them.

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Toward Bulk Power System Resilience

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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

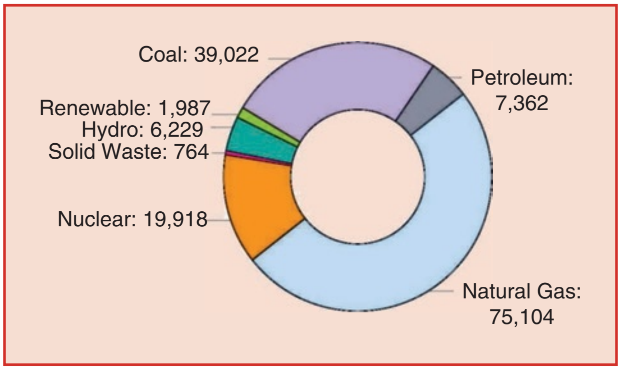

figure 1. Cleared capacity for the 2021–2022 delivery year (in megawatts).

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

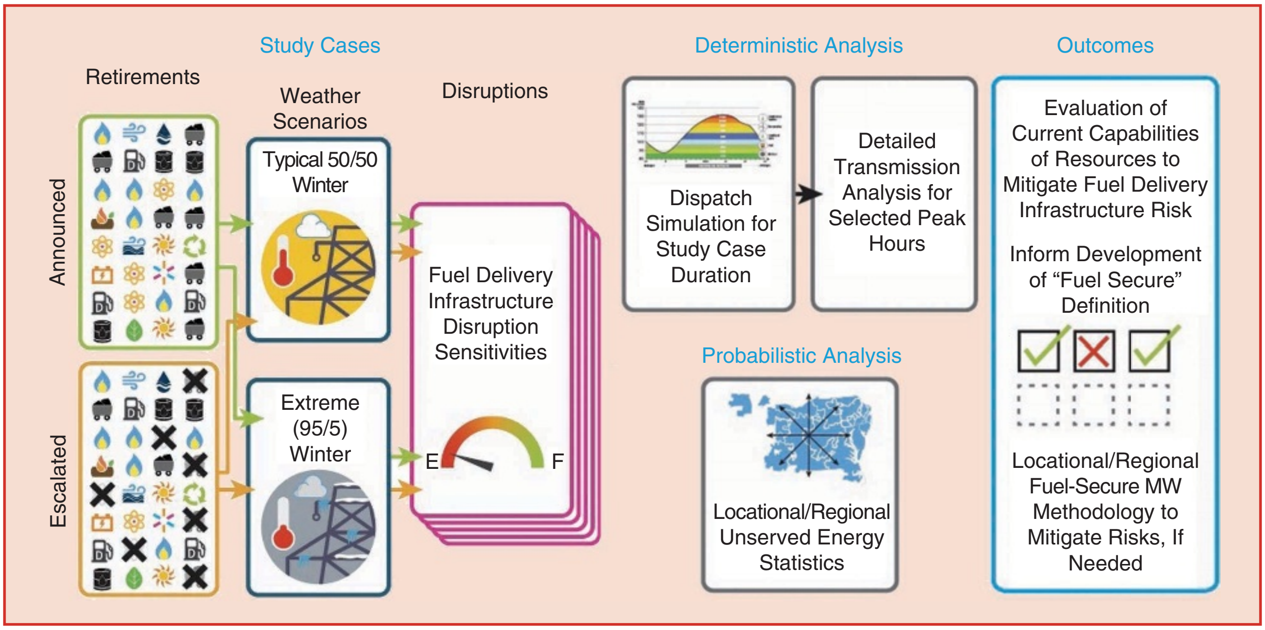

figure 2. A fuel security analysis approach overview.

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

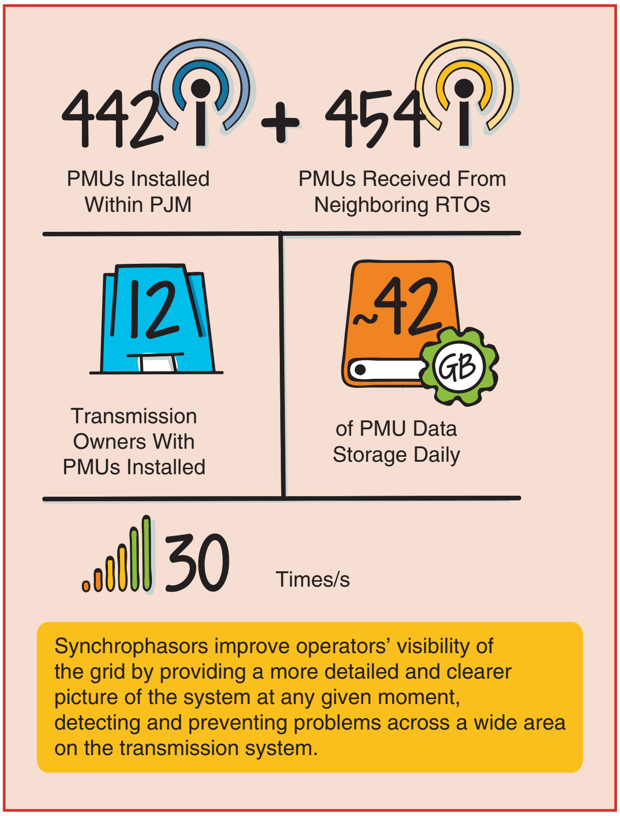

figure 3. PJM PMU statistics.

> 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

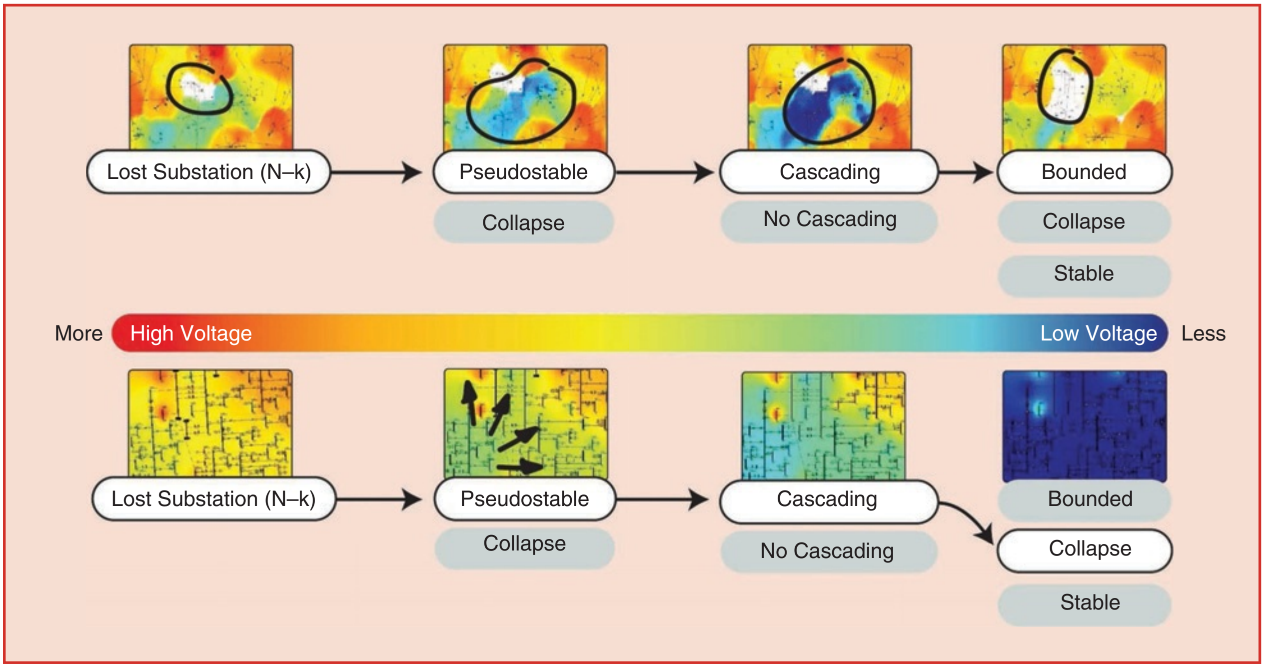

figure 4. Example images from the cascading-tree assessment.

> 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.

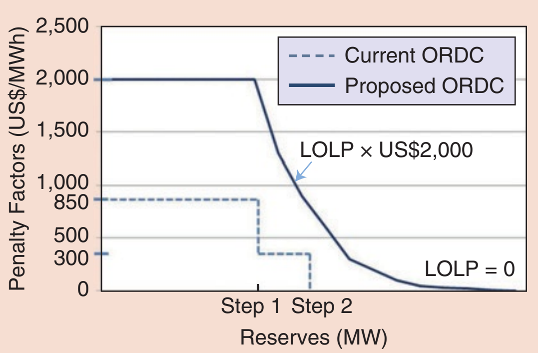

figure 5. The proposed ORDC changes. LOLP: loss-of-load probability.

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

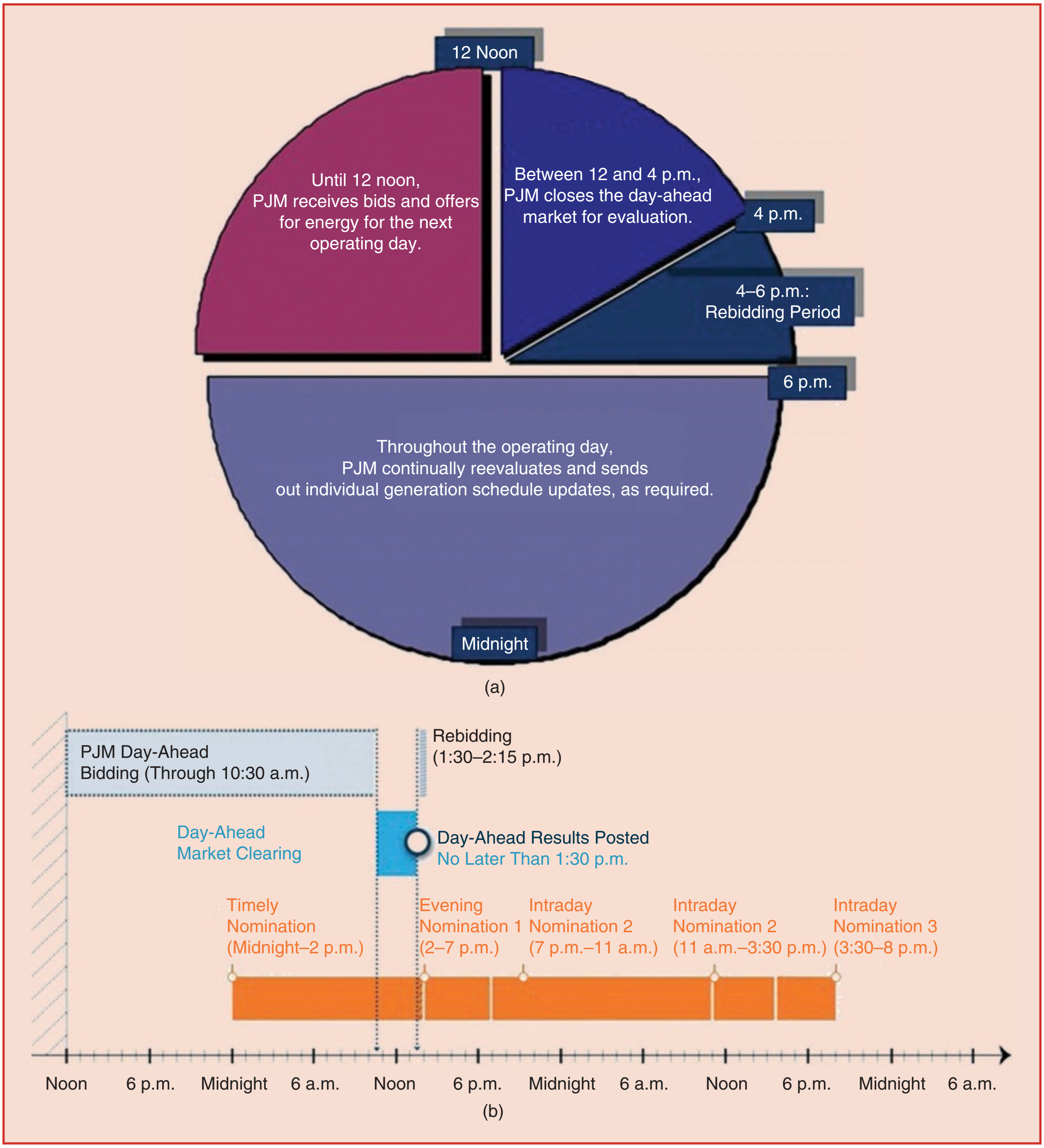

figure 6. The day-ahead market timeline (a) before and (b) after 1 April 2016.

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

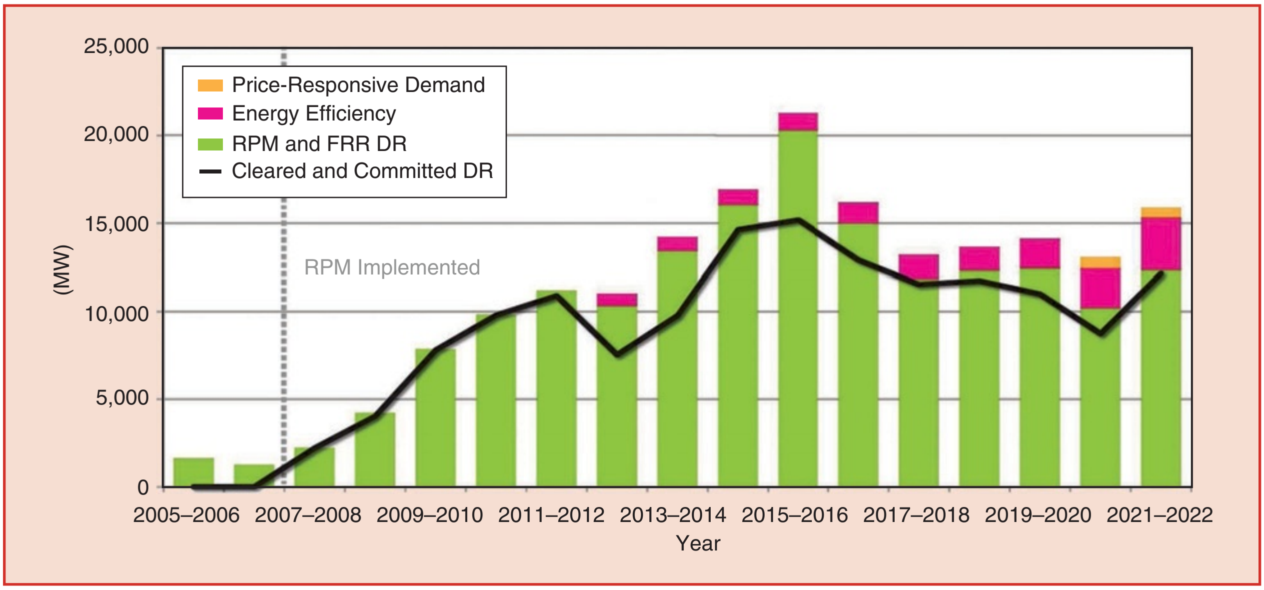

figure 7. DR in PJM markets. FRR: fixed resource requirement.

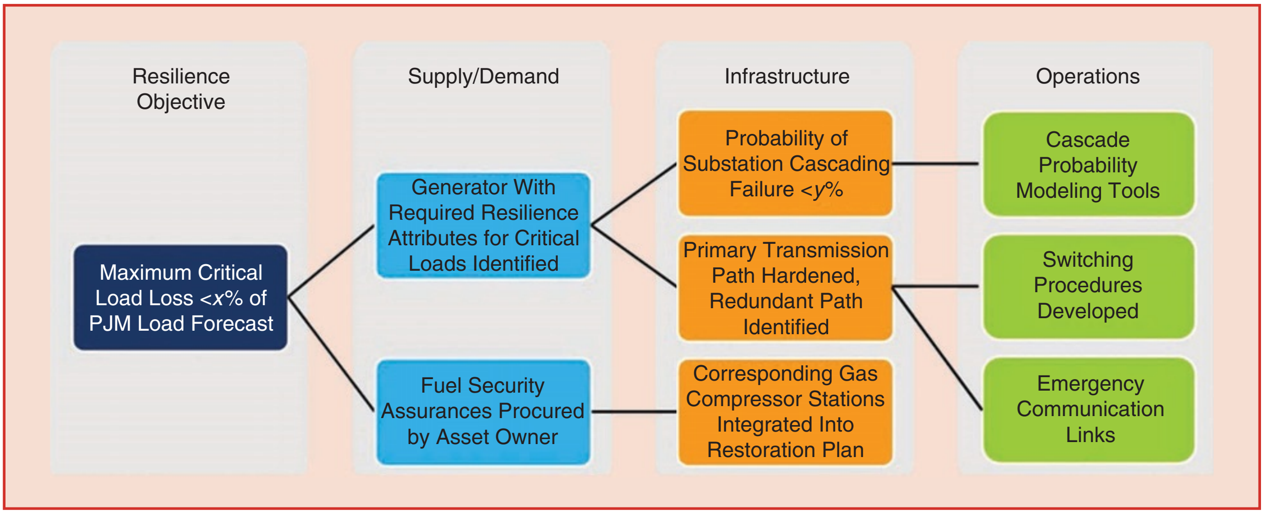

figure 8. The resilience matrix.

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

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Power System Restoration

Meeting the Challenge to Resiliency From Distributed Generation

THE PARADIGM SHIFT IN THE configuration of the power system in Europe and the United States away from large conventional synchronous generators to small generating units distributed over large geographical areas, many of which are powered by intermittent renewable resources, has a major effect on various aspects of system operations, most importantly dispatch and commitment processes. This article discusses the challenges for power system restoration and how to meet those challenges.

As the power system becomes increasingly reliant on distributed generation (DG), the majority of which is connected at the distribution level, a new dimension in grid cooperation between the independent system operator/regional system operator (ISO/RTO), transmission system operator (TSO) and distribution system operator (DSO) is being created for system restoration. For a system that has high degree of DG penetration, the following factors must be considered while examining restoration: 1) the observability of distributed generators; 2) interaction among ISO/RTOs, TSOs,

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and DSOs; 3) command and control structure of the network; and 4) the regulatory framework.

Utilities are now considering the integration of DG into their restoration plans and personnel training with scenarios that depend on the level of penetration of DG. For each scenario, the impacts on restoration plans are elaborated according to the emerging needs for observability and forecasts; enhanced ISO/RTO-TSO-DSO coordination; changed command and control structures; and improvements in the technical, organizational, and regulatory areas with an emphasis on grid operations. This article concludes with proposals for training sessions in which TSOs and DSOs in Europe confront the challenges for system restoration in an operating environment with significant levels of DG.

Power System Restoration

The current approach to power system restoration is often a combination of "top down and bottom up" coordination among transmission and generation operators. The TSO-led process starts with the black start of large generators, the creation of stable islands with balanced generation and loads along a transmission corridor, synchronizing the islands, and, eventually, fully restoring the system and resuming normal operations. The shift from large centralized synchronous generating units to small distributed generators, many of which are powered by intermittent renewable resources, introduces a new dimension in grid cooperation for TSOs and DSOs— most importantly the approach to power system restoration.

Restoration Requirements

Although TSO and DSO cooperation continues to be the overriding requirement for system restoration, the tools and training that are made available to personnel must change as power system operations become more dependent on DG with intermittent energy sources, the majority of which are connected at the distribution (DSO) level. National laws in Germany make it mandatory for the system operator to include renewables in its generation mix, even if this requires compensating other generators for shutting down their planned production. Such rules create conflicts in normal operating conditions, which are further aggravated in an emergency or restoration situation.

The main issue in restoration is that the system operator (i.e., the TSO) has ultimate responsibility for system security but cannot adequately control DG. Technical tools, control systems, and communications can often be inadequate, and the regulatory framework may be incomplete or conflict with other participants' goals. This creates a need to

- ✔ harmonize market rules to make a level playing field for all
- ✔ provide authority for system operators to
  - overrule market considerations during emergencies
  - maintain system integrity
  - order disconnection and reconnection of the DG for safe operation
- ✔ mandate a minimum control and command structure for distributed generators
- ✔ harmonize technical connectivity requirements
- ✔ allow new roles and players with clearly defined rules for demand response.

Restoration Practices

Important considerations for adapting restoration practices to an operating environment with a high penetration of DG are 1) the observability of distributed generators, 2) interaction between TSOs and DSOs, 3) command and control structure of the network, and 4) the regulatory framework. Systems with higher penetrations of DG are highly dependent on observability and controllability of most active components. This requires new concepts for system management both in general and specifically in the restoration plan. These plans clearly demand an understanding of active network elements at all levels and benefit from command and communication channel systems.

Survey of European Grid Operators

The CIGRE Joint Working Group C2/6.36 conducted a survey on the role of DG in the restoration process. The results of this survey were published in "System Operation Emphasizing DSO/TSO Interaction and Coordination" (June 2018). Among the major findings were the following:

- ✔ Poor observability does not allow for the participation of DG in restoration plans.
- ✔ Data and voice communication systems and processes are still being developed to cater for DG.
- ✔ Utilities with higher penetration levels are now considering the integration of DG into their restoration plans.

Scenarios for System Restoration

Scenarios for system restoration depend on the degree of DG penetration. For each scenario, the impacts on restoration are elaborated for each of the identified factors, e.g., emerging needs for observability and forecasts, enhanced TSO-DSO coordination, advanced command and control structures, and the impact on restoration plans.

ENTSO-E Awareness System

The European Network of Transmission System Operators for Electricity (ENTSO-E) Awareness System was established as a result of a recommendation from European regulatory authorities after a large system disturbance in November 2006 in the continental European system. All European TSOs send their frequency, scheduled and actual flow, and area control error to a central system known as the ENTSO-E Awareness System. Each participating TSO receives an online overview state of the Pan-European system, making it aware of the situation of the complete network. In addition to the measurements and planned values, the TSO can indicate its system states as normal, disturbed, or emergency using simple traffic lights green, amber, and red. This provides an effective way to show the system state for each of the TSOs. The system has been in operation for more than eight years and is now an integral part of the control room displays of European TSOs.

Operational Tasks—DG Factors

System operators are responsible for system integrity, regardless of the type of generation or its interconnection to the grid. The primary operational task of both TSOs and DSOs is to keep the grid within operational boundaries, i.e., maintain voltage, frequency, and current within system limits. This is more complex in systems with high levels of DG with intermittent energy resources.

System Balancing

System balancing—the control of frequency and power exchange—is a major responsibility of the TSO. Deviation from generation forecasts creates imbalances, leading to larger frequency excursions due to the poor forecasts. The stochastic behavior of DG makes balancing difficult.

An accurate forecast of DG is an important tool for a TSO in addressing these deviations. Typically, the TSO forecasts for its control area include nonobservable DSO areas. Sufficient control power is needed to handle imbalances. For primary control power, the TSO must rely on locally provided conventional generation units. In the ENTSO-E continental Europe area (Figure 1), automatic load frequency controllers are applied for activation of control power

figure 1. The ENTSO-E transmission grid interconnected network. (Source: ENTSO-E: https://www.entsoe.eu/data/map/downloads; used with permission.)

(secondary control power). Activated secondary control power is released by tertiary control power, mostly manually activated by the TSO.

However, neither the TSO nor DSO can control all conventional generation directly. With increasing levels of DG, the DSO is taking over more "system tasks" such as the provision of power for system balancing. Thus, DSOs are starting to provide contributions to ancillary services, including black start.

Congestion Management

Congestion management is independent of voltage level. Loop flows make this more challenging in highly meshed systems (such as those operated by TSOs), than in radial systems (medium voltage). An example of congestion that affects power restoration is the coupling of transformer loop flows between TSOs and DSOs, which must be respected in restoration plans. In the case of an overload, caused by a DG infeed, the infeed needs to be reduced. Here, observability and controllability of DG in the DSO systems can be crucial. The DSO must reduce infeeds in a deliberate and transparent way by 1) analyzing the locations where it is possible to reduce infeeds and the impact of the reduction of flows on the critical circuits, 2) determining optimal reductions of flows, and 3) identifying the impact of reductions on transformer flows.

In the case of congestion, DG usually cannot just be reduced. Redispatch typically takes place at the same time conventional generation is ramped up to maintain system balance. Redispatch of the bulk system is a TSO responsibility.

Voltage control is usually done in cooperation with conventional generation units. The TSO and DSO communicate directly and in a collaborative way. Clear communication instructions must be in place that direct generator operators and all power electronics-based devices, such as static var compensators. Voltage control with DG becomes more important as conventional synchronous machine generation is replaced.

Due to these complexities in the operation of the power system, the system control and data acquisition (SCADA) system and, where appropriate, the energy management system (EMS) of the DSO system must provide support to its own operators and to those of the TSO.

Controllability and Observability of DG

One main difference between conventional centralized generation and decentralized generation is the absence of dedicated operators for decentralized production. Wind turbines and photovoltaic cells usually operate automatically and are optimized for operation under normal conditions. They perform tasks such as automatic startup (synchronized) and ramping to maximum available power. DSO control centers (Figure 2) play a crucial role in DG

figure 2. The Swissgrid Control Room. (Source: Swissgrid; used with permission.)

> The shift from large centralized synchronous generating units to small distributed generators, many of which are powered by intermittent renewable resources, introduces a new dimension in grid cooperation.

operation, especially in terms of the observability of DG units, since available information is collected and concentrated by the DSOs' SCADA systems.

Aggregated Distributed Energy Resources and Microgrids

Aggregated distributed energy resources (DERs) and microgrid concepts are potential solutions to the visibility and control of DG. Aggregated DERs can be a virtual power plant capable of forming an island when matched with suitably sized loads. Microgrids are islands of balanced generation and loads. In the future they may be used by TSOs and DSOs to facilitate the restoration process.

Operational Tasks in Restoration

Changing Operational Focus

Transmission system states can be classified into normal, alert, emergency, blackout, or restorative (see Knight in the "For Further Reading" section). A transmission system is considered to be in a "blackout state" if more than 50% of demand is lost and the formal restoration process must be initiated. In the restorative state, the focus changes to restoring supply to customers, maintaining voltage and frequency control, and unplanned decisions and actions. Unplanned decisions and actions are those that are in response to events as the restoration process unfolds. They are not anticipated and written in procedures. Additionally, the coordination of multiple control center actions is crucial. Control centers for transmission systems, the underlying distribution systems, and generating units must interact in a coordinated way.

The coordination of tasks among control centers should be part of individual restoration plans. The ENTSO-E operational policy considers restoration an ancillary service, a responsibility of the TSO. The TSO must require that all DSO-connected and conventional synchronous generators have restoration plans available. TSOs are responsible to provide black start capabilities for the transmission system.

The critical tasks in restoration are as follows:

- ✔ initialization
- ✔ frequency control
- ✔ voltage control
- ✔ control of conventional synchronous generation (centralized)
- ✔ control of DG
- ✔ control of power flows and interchanges
- ✔ customer supply.

The main objective of system operation is to always keep the critical system values within operational limits. Common strategies for restoration must always maintain safety and security, independent of the level of DG penetration in the system.

Phases in Restoration

After a blackout, the TSO coordinates and executes the restoration process in its control area. In the analysis and coordination phase, the scale of the outage is identified. All parties involved, such as neighboring TSOs, DSOs, dispatch centers, and conventional generation, are informed of the blackout. Each party makes its own preparations, which are usually based on predefined plans. Communication is established. All market-driven activities are suspended. The TSO collects cross-border information for restoration strategy development. The TSO and DSO initially prepare the grids for restoration by splitting them both horizontally and vertically. Also, in many restoration scenarios, all circuit breakers are opened in the blacked-out network to protect loads and generators. Other switching actions such as the preparation of black start paths depend on the chosen strategy.

Generation units have additional preparation tasks. These include the following:

- ✔ securing generation units' house loads
- ✔ preparation of black start units
- ✔ preparation of tripped units for start up
- ✔ selection of control modes for restoration (switching of steam units to bypass control, activation of speed control or power control mode, voltage control mode)
- ✔ observing safety regulations while switching: before any switching can be done, a network operator must make sure that no one is working on that part of the network, lines are not down, and that there is enough interrupt capability when circuit breakers close into a short circuit so as not to damage equipment
- ✔ ensuring synchronization can take place before closing two energized portions of the system.

A neighboring TSO can sometimes provide support over ties, which today can be provided via either high-voltage ac or high-voltage dc links. The partner provides voltage support and controls the frequency. Both TSOs must agree on a band of exchange power for the control purpose. This enables the supporting TSO to organize sufficient control power for frequency control with restoration of the grid

The main issue in restoration is that the system operator has ultimate responsibility for system security but cannot adequately control DG.

controlled by the local TSO through a stepwise energization of the grid. Here, voltage control is challenging particularly because energizing lines without load can lead to high voltages (Ferranti effect), which must be compensated with coils and/or generation units. Generating units connected to the system need to be "loaded" so active and reactive power can be provided to the underlying DSO systems, where customers can be resupplied.

The major activity in top-down cases is the coordination of exchange power, i.e., both active and reactive. The amount of exchange power provided to each DSO (regional system) is dependent on available exchange power from the supporting TSO plus available conventional generation. The restoration process is unique to each control area. TSOs need to provide simulator-based training sessions to successfully manage this "multilevel" task with all its partners.

If no external support is available, the TSO may rely on contracted generators for black start in its control area. In this case the coordination of exchange power is replaced by frequency control. All imbalances between generation and load directly influence the frequency. The major tasks in this black start situation are balancing and frequency control. For the DSOs, the strategy is still top-down. However, due to unstable frequencies during load reconnection, the exchange bands are smaller and "load-step" sizes must be carefully selected. Furthermore, available reactive power is limited and dependent on size and location of conventional generation units.

In some cases, the DSO can perform black start, especially when midsize hydro pump storage units are connected to the DSO network. In that case, a bottom-up strategy is followed, i.e., starting at the regional level and then providing power to the TSO. Operational tasks are the same as in the TSO black start case. Voltage control is less critical due to the lower amount of reactive power involved in comparison with the transmission system during a top-down strategy.

In the first restoration phase, the focus is on the

- ✔ resupply of house load (station service load for substations and generators)
- ✔ resupply of critical infrastructure
- ✔ creation of a stable system (both voltage and frequency).

In the second restoration phase

- ✔ the system is extended
- ✔ customers are supplied
- ✔ unit commitment is organized depending on primary energy sources (e.g., coordination of pump storage and conventional generation).

In the final restoration phase

- ✔ the system is meshed to avoid overloads
- ✔ frequency is resynchronized with partners
- ✔ load frequency control (LFC) is returned to operation.

In all cases, the system operator continuously monitors the critical operational values and takes the required corrective actions. It should also be noted that the time available for a number of these tasks is limited due to factors such as battery life and standby generators' fuel reserves.

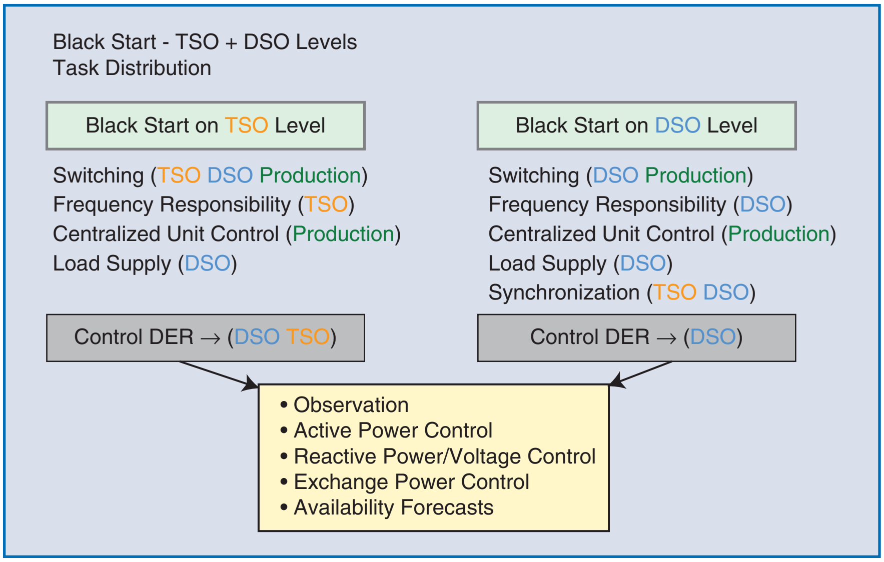

figure 3. The task distribution of black start at TSO and DSO levels.

Operational Tasks for Restoration With High Levels of DG

Since they are based on predefined operational criteria, system restoration tasks are generally quite similar (see Figure 3). However, their allocation at participating control centers can differ significantly. This varies according to the dependency on decentralized generation, which, in turn, varies according to the level of DER penetration. This section examines different restoration cases with various levels of DER penetration.

Case Definitions

Due to the large number of possible variations in task allocation, as a first step, the following boundary conditions should apply in the restoration process after a complete blackout in the TSO system:

- ✔ The TSO performs a black start at the transmission level. For the DSO(s), a top-down strategy is performed. Consequently, the operational task "frequency control" always must be performed by the TSO.
- ✔ In the TSO system, centralized generation is available. These generation units are coordinated by the TSO and can be used for voltage control in the TSO system.
- ✔ Pumped storage is available at the TSO.
- ✔ In the DSO system, no centralized generation is available (by definition).
- ✔ In the TSO system, there is no DG.
- ✔ All customers are connected to the DSO systems, which comprise voltage levels from 110 kV to 150 kV, and medium voltage. Often, these voltage levels are controlled by different control centers.

The following limitations summarize changes in restoration issues for various levels of DG at the DSO:

- ✔ *No DG, passive system (passive DSO):* This case is similar to traditional distribution systems that serve load without local generation.
- ✔ *DG not controllable, low penetration:* That means the system load can be supplied with centralized generation (low DG: not controllable).
- ✔ *DG not controllable, high penetration:* That means the system load cannot be supplied with conventional generation (high DG: not controllable).
- ✔ *DG partly controllable, high penetration:* That means the system load cannot be supplied with conventional generation. Controllability of DG comprises limitation of active power (known as generation management) (high DG: partly controllable active power).
- ✔ *DG partly controllable, high penetration:* That means that the system load cannot be supplied with conventional generation. Controllability of DG comprises both limitation of active power (generation management) and voltage support (high DG: active and reactive power partly controllable).

The cases "all DG controllable" and "no conventional generation" do not exist in the integrated power systems of Europe.

One common principle that applies to all levels of DG penetration is the compliance to security rules while performing the switching operations. In a passive DSO, the lower voltage level will not be live, as the power flow is strictly from higher voltage levels to lower voltage levels. The possibility that lower voltage levels may already be energized increases with higher levels of DG penetration. This is especially true where observability and controllability of DG is low from a TSO perspective.

Passive DSO

The DSO without any DG or conventional generation is termed a passive *DSO*. The main task for a passive DSO is to connect load, usually on demand from the TSO. In this case, all restoration strategies will end up in a top-down scenario with the main task being voltage control.

The restoration process is completely controlled by the TSO. The DSO can support the TSO through

- ✔ the observation of active power delivery from the TSO to the DSO
- ✔ keeping both amount and step-size within agreed-upon limits while reconnecting customers
- ✔ the observation of reactive power exchange.

In case of any limit violation, the DSO must contact the TSO. Disconnection of load is the only operational measure that can be performed by the DSO on an emergency basis without coordination with, or approval by, the TSO.

Low Uncontrollable DG

The DSOs with low DG penetration may be treated as passive DSOs from an operational perspective. At the DSO level there is DG, but it may not be observable or controllable. In the restoration preparation phase, all DG should be disconnected from the system, insofar as this is possible. In some cases, all DG cannot be completely disconnected, resulting in the remaining DG automatically resynchronizing and supplying reactive power. Here cases arise where the TSO must consider DG infeeds in the restoration strategy. After the TSO provides reactive power (and hence voltage support to the DSO system and connecting load), DG may automatically synchronize and feed in maximum power that may reverse power flows from the DSO to the TSO system. Due to the low level of DG, this usually does not create overloads in the DSO systems or on coupling transformers. The fluctuating load must be balanced; therefore, the demand for reserve power increases. In the restoration process, the TSO can control the frequency by

- ✔ observing (reversed) DSO power exchanges
- ✔ issuing coordinated set points to conventional generation
- ✔ allowing the DSO to connect additional load.

In contrast to the previous case, the coordination work is more demanding. Here again, in case of any limit violation, the DSO must contact the TSO.

High Uncontrollable DG

In this case, the DSO is still passive, operationally speaking, but the DG can be observed. From the DSO point of view, this case is critical. DG is needed for restoration but cannot be controlled. The reversed power flows may lead to congestion in the DSO grid, both on lines and transformers. The rapidly changing load on DSO lines leads to rapidly changing voltage profiles. The DSO has the following limited control capabilities, which are typically slow acting:

- ✔ tap changers on TSO-DSO transformers for voltage control
- ✔ connect or disconnect load and DG for handling congestion.

This requires additional balancing tasks. Reserve power demand increases since the frequency must be kept within operational limits. Additional supporting tools for the TSO could be

- ✔ more accurate wind and solar forecasts to help manage the control power required to compensate for fluctuations
- ✔ use of storage resources, like pumped hydro, to provide frequency control. Here, storage management is an additional challenge.

The DSO may run into critical situations but cannot solve them independently from the TSO. TSO-DSO coordination is required to manage 1) power exchanges and 2) the DSO system state (voltage and overload).

High DG With Active Power Limitations

Here again the DSO system might be overloaded. But the DSO now has its own operational capabilities, which makes life easier for the TSO because the DSO can solve congestion problems individually by limiting power flows and the TSO and DSO can agree on a band of exchange power (active) between their systems.

A band of exchange power enables the TSO to plan for the provision of control power because, up to a certain level, active power fluctuation is compensated for directly by the DSO. Now the DSO needs its own forecast tools. Only in the case of agreed limit violations does the TSO support the DSO since the TSO still leads the restoration process. As the amount of information exchange rises, additional supporting tools may be required to support the restoration process.

High DG With Active Power Limitation and Voltage Control

In this case, the DSO can control voltage profiles with DG. This is usually challenging due to the large quantity of DG. It is difficult to assess where to change voltage or reactive power set points to create the desired voltage profile.

Here an EMS application is required, e.g., an optimal power flow with suggestions for reactive set points. Unfortunately, these systems are unlikely to function correctly in the early stages of restoration due to separations in the system.

Overview of Expanding DSO Tasks

Figure 4 summarizes expanding DSO tasks with increasing levels of DG and increasing observability and controllability. In the ENTSO-E system, several real-time tools have been installed to support operators from different TSOs in handling critical situations from basic alerts up to power system restoration. For TSO–TSO exchange, the ENTSO-E Awareness System platform has been established. This tool provides the following information:

- ✔ measurements of frequency, area control errors (determined by LFC), cross-border exchanges, and balancing and generation
- ✔ operational information on TSO system states via exchange of predefined messages as traffic light colors.

Similar tools are employed in the Nordic regions (Denmark, Finland, Iceland, Norway, and Sweden). These pure TSO systems are not designed to interact with, or to be used by, DSOs.

	Control of TSO-DSO Exchange Power	Observe DG	Control DG	Congestion Handling	Voltage Support With DG
1) Passive DSO	TSO	—	—	TSO	—
2) Low DG—No Control	TSO	TSO	—	TSO	—
3) High DG—No Control	TSO	TSO/DSO	—	TSO/DSO	—
4) High DG—Active Power Partly Controllable	TSO/DSO	TSO/DSO	DSO	TSO/DSO	—
5) High DG—Active and Reactive Power Partly Controllable	TSO/DSO	TSO/DSO	DSO	TSO/DSO	DSO

figure 4. A summary of DSO tasks and examples of tools for coordinated operation.

New TSO-DSO information systems are being deployed. These include the Austrian Awareness System (AAS) and the Regional Alarm and Awareness System, new tools that aim to maximize information exchange between all grid operators, including DSOs.

The Austrian Awareness System

The TSOs of the Regional Group Continental Europe (RGCE) use the European Awareness System (EAS) for information exchange across national borders. The communication between TSOs and their underlying DSOs is often based on telephone communication. In the Austrian Power Grid (APG), the TSO and DSOs have

System operators in both transmission and distribution systems are confronted with new challenges for power restoration in both technical and organizational dimensions.

tailor-made emergency and restoration plans with a focus on coordination and communications—the AAS. The AAS uses electronic data and information exchange that is designed to reduce the need for oral communication via telephone. This is efficient and reduces misunderstandings.

The AAS used for information exchange between the TSO and TSO-connected DSOs is implemented in the TSO control center and 10 TSO-connected DSO control centers. Information is collected from TSO transformer substations within each DSO system.

Since most renewable energy resources are connected at the DSO level, TSO/DSO information exchange within the control area is required for system awareness. The exchanged information helps the APG to determine the overall system state, which is communicated via the EAS to the interconnected TSOs of RGCE. At the same time, the connected DSOs receive compressed information about the system state in the APG's control area and the neighboring part of the RGCE.

System defense and restoration requires a detailed overview of the actual situation of the whole system, such as an adequate overview of areas and loads that are not supplied. Most TSOs do not have a detailed view of the DSO systems to determine the state of the whole system. Again, the communication between TSOs and DSOs is crucial.

Information exchanges specific to restoration tasks across TSO and DSO responsibility areas include

- ✔ ad hoc power/frequency balancing, including loading of generators to their technically required minimum load respecting load gradients
- ✔ synchronizing islands, which requests the TSO for a quasi-steady-state frequency and therefore a stop in generation ramping and load connection
- ✔ coordinated load reconnection impacted by the exchange of power between TSO and DSOs.

Depending on the actual system state, boundary conditions resulting from neighboring TSOs' and underlying DSOs' systems forecasts of renewable energy sources (RES) are required.

Training and Tools

Training sessions for DSOs and TSOs—using tools that recognize DG as a significant factor for power restoration—are essential for resiliency under scenarios of high DG penetration. System operators in both transmission and distribution systems are confronted with new challenges for power restoration in both technical and organizational dimensions. It is imperative that they train together using simulation tools, share situational awareness, and coordinate strategies across boundaries.

The breadth of scenarios for power system restoration with DG defines the challenges that TSOs and DSOs must now confront. Meeting these challenges requires training with suitable tools. Simulator-based training sessions are the most appropriate way to train operators from the transmission, distribution, and generation facilities in new restoration techniques. New training scenarios, to augment traditional scenarios, are required for systems with significant amounts of DG.

Tools that are specifically designed to support system restoration with high shares of RES need to be developed and installed at training centers and control rooms. In the future, tools will be developed to include simulator training for intercompany emergency and restoration with the participation of TSOs, DSOs and multiple DER control centers. This is shown in Figure 5.

The dynamic real-time training simulator being used today for restoration training needs to be updated to cope with power systems with a high penetration of DG under

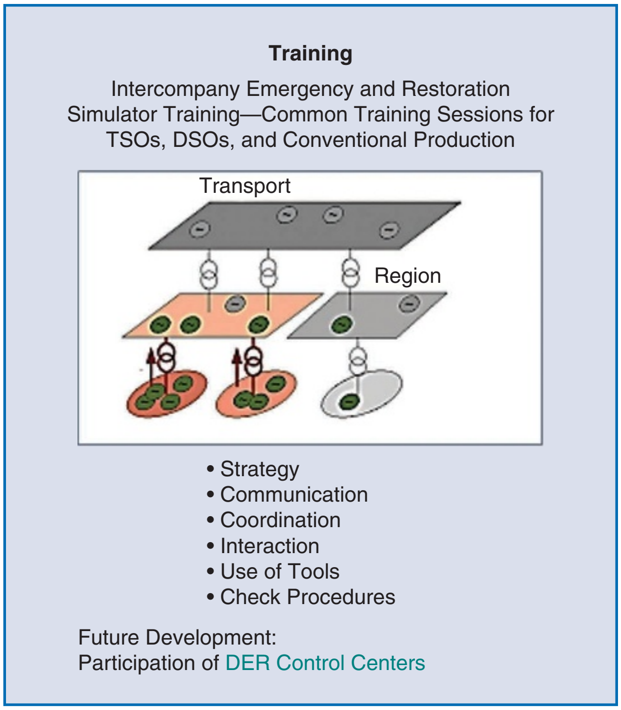

figure 5. The future of simulator training for intercompany emergencies and restoration.

The grid is not resilient unless it can defend itself against disruption that can lead to system collapse, respond to that disruption, and restore normal operations within a reasonable timeframe.

system restoration conditions. This requires simplified models of various DG generation units as well as representations of unobservable grid areas from the control room operator's point of view for both the TSO and DSO.

Significant amounts of DG will be reconnected during load restoration. TSOs must be able to monitor and control the response of generation units connected at the distribution level during the restoration process. Otherwise there is a risk of system collapse during the restoration process. This risk increases with the level of DG units. In this situation the following steps are taken:

- ✔ the rethinking of existing restoration strategies and developing new or advanced strategies
- ✔ the deployment of updated restoration strategies in operator training
- ✔ investigations related to the controllability of DG installations with respect to power/frequency balancing and managing the volt/var balance of the power system
- ✔ the development of special operator tools dedicated to the restoration process for situational awareness and decision support.

An innovative restoration support tool (RST) for use by control room operators in training and real-time system restoration would have the following features:

- ✔ estimation of maximum tolerable load pickup
- ✔ estimation of maximum tolerable DG reconnection
- ✔ estimation of maximum tolerable conventional unit resynchronization
- ✔ contingency analysis
- ✔ security controlled switching
- ✔ flexibility assessment.

It is difficult to envisage how variable generation such as wind and solar can be reliably incorporated into any restoration plan without the use of a tool such as the RST, due to the need for the TSO/DSO to jointly contend with the large number new variables. The RST would be a bridge between the TSO and DSO, facilitating the cooperation that is critical to reliable operations in normal times and efficient restoration in times of grid separation.

Other decision support tools for restoration have been proposed, but they have had the capability of dealing with variable or intermittent generation. At the TSO level, restoration plans can utilize traditional methodologies, i.e., only use synchronous generators, but this approach will encounter problems when wind turbines and solar panels are reconnected during load restoration.

Summary

The paradigm shift toward DG changes the TSO approach to power system restoration. Among the key factors deserving special attention are observability of distributed generators, interaction between TSOs and DSOs, the command and control structure of the network, and an evolving regulatory framework.

The grid is not resilient unless it can defend itself against disruption that can lead to system collapse, respond to that disruption, and restore normal operations within a reasonable timeframe. The challenge of DG to system defense and restoration is being met though new operational practices and effective training.

For Further Reading

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From Reliability to Resilience


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Planning the Grid Against the Extremes

ALTHOUGH EXTREME EVENTS, MAINLY NATURAL disasters and climate change-driven severe weather, are the result of naturally occurring processes, power system planners, regulators, and policy makers do not usually recognize them within network reliability standards. Instead, planners have historically designed the electric power infrastructure accounting for the so-called credible (or "average") outages that usually represent single or (some kind of) simultaneous faults (e.g., faults on double circuits).

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> While doing so, we highlight the fundamental physical and decision makers' risk attitude features that distinguish reliability-driven from resilience-driven investments.

A reliable power system would be operated in a secure way if it were able to withstand these faults without threatening the integrity of system operation while preserving the continuity of supply to customers. However, the impact of recent extreme events on power systems, e.g., bushfires in Australia, flooding events in the United Kingdom, storms in the Americas, and earthquakes in countries located at the edge of the Pacific Ocean, which have even led to chaotic societal situations, goes far beyond N–1 or N–2 outages and clearly highlights the need for rethinking current planning practices.

For example, during the last 10 years, Chile has, on an annual basis, experienced more than 300 earthquakes above 4.5 Mw, with several hours of interruptions each year. In the case of the United Kingdom, severe storms and floods result in power outages for tens of thousands of customers per year. In 2016, for instance, floods were responsible for power interruptions that lasted up to 56 h in Northwest England. These are only a few examples worldwide where the aftermath of catastrophic extreme events brought resilience into discussions among power system planners, regulators, and policy makers.

In this context, and within the broader framework of low-carbon energy network planning being uncertain, in this article, we analyze a set of key questions pertinent to the resilience debate:

- ✔ How can we incorporate resilience thinking into power system planning, thus going beyond traditional reliability-driven planning?
- ✔ Can the negative impacts of natural hazards on electricity supply be mitigated through planning measures?
- ✔ What is the optimum portfolio of measures for boosting power grid resilience to such extreme events?
- ✔ How can we build a power grid that is both robust and flexible enough to withstand events that have possibly never been experienced before?

Because such questions are troubling to decision makers around the world, our aim is to introduce a general, quantitative framework that identifies optimal portfolios of resilience-enhancing investments and demonstrates them through several illustrative case studies. While doing so, we highlight the fundamental physical and decision makers' risk-attitude features that distinguish reliability-driven from resilience-driven investments. Our framework, which was elaborated on during a United Kingdom–Chile joint project and implemented in actual operation and planning mechanisms in the Chilean power system, can thus be seen as a fundamental development to extend, in a transparent and consistent way, current reliability practices toward more resilient grids.

Incorporating Resilience in Network Planning

With its growing relevance and interest to our IEEE Power & Energy Society (PES), many definitions of power system resilience have emerged lately. In the technical report PES-TR65 published by the IEEE in April 2018, resilience was defined as "the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event." In general, these resilience definitions mainly focus on characterizing the term *extreme event*, which could threaten power systems, and on the key features that a power system should possess within the multifaceted concept of resilience to minimize the risk exposure to these extreme events. In particular, the following two points provide insight across all definitions and specific relevance to the network planners who aim to identify resilient network enhancements:

1) an emphasis on extreme or catastrophic events, formally referred to as high impact and low probability (HILP) (also known as *black swan*) events, which require some form of hedging
2) an emphasis on the time-varying nature of resilience, including and quantifying the various phases before and during a severe event as well as after it (when the system recovers).

Capturing HILP Events Within Network Planning: The Need for Risk-Averse Modeling

Historically, (deterministic) network reliability standards have typically ignored any contingency beyond "credible" ones, e.g., N–1/N–2. This has resulted in a bias toward building more and more infrastructure, mainly to provide redundancy to deal effectively with any outage that might threaten the uninterrupted power supply. However, experience with extreme events clearly shows that this reliability-driven approach of making the infrastructure "bigger and stronger" through redundancy and reinforcements may not be effective to hedge against multiple simultaneous outages or outages occurring in rapid succession. In fact, very extreme events cause outages well beyond credible ones, potentially affecting hundreds of network components. In other words, extreme events typically lead to considering N–X outages,

> It is evident that current planning standards need to be modified to allow HILP events to be accounted for within the network design and expansion decision-making process.

with *X* being greater or much greater than 1 or 2 and even in the order of hundreds or more. Indeed, here lies one of the fundamental differences between reliability and resilience, at least in the context of network planning. Planners may then intuitively realize that, although it improves reliability, more redundancy may not necessarily improve system resilience to extreme events. Alternatively, flexible ("smarter") solutions could provide more viable options that enhance resilience by helping to withstand the initial adverse impacts of extreme events as well as by supporting the efficient response and prompt recovery of the system.

In the new context outlined in this section, could hybrid solutions (where *hybrid* refers to both infrastructure/network, i.e., to provide redundancy and robustness, and noninfrastructure/non-network or smart operational solutions, that is, to provide flexibility) constitute the optimal portfolio to boost resilience to extreme events? Although this is still an open research point and likely to be case specific, if we want to keep the lights on or at least pursue an acceptable level of system operation under a large array of circumstances (beyond so-called credible contingencies), it is evident that current planning standards need to be modified to allow HILP events to be accounted for within the network design and expansion decision-making process. However, the key question here is how? Even though no straightforward answer exists, in this section, we discuss a few possible approaches while recognizing that it is technically unrealistic (and not economically viable) to consider targets of 100% reliable supply after extreme events and, at the same time, acknowledge that the system should meet classical (deterministic) reliability standards that consider only credible outages.

A first approach to incorporate HILP events within network investment planning could adopt probabilistic (or, in mathematical programming terminology, stochastic) models that explicitly consider the associated probabilities and resulting impacts of many states of the system, including the intact system and simultaneous outage scenarios. These impacts are usually measured in terms of energy not supplied (ENS) and valued through economic metrics such as the value of lost load (VoLL). More specifically, in the probabilistic reliability assessment pioneered by Billinton and Allan, the resulting estimated costs from the ENS are averaged (weighted by probability) across all of the modeled scenarios and optimized against additional investment and operational costs. Network investments are thus well justified as a tradeoff between economics and security of supply and, if we neglect, for simplicity, operational costs (e.g., congestion costs, losses, and so on), carried out up to the point where the marginal cost of additional investment equals the marginal benefit of enhanced reliability. This is graphically illustrated in Figure 1, where the reliability cost is measured as the expected energy not supplied (EENS) × the VoLL. This probabilistic approach, however, presents a fundamental limitation to properly addressing HILP events and informs appropriate investment decisions as a hedge against them, as we discuss further in this section.

HILP events are, by definition, very rare, and their impact on average indicators such as the EENS is therefore very limited. For example, our analysis shows that, on average, it would be economically optimal for Chile's power system to suffer the consequences of very large earthquakes every 15 years rather than invest in further assets to reinforce and harden the power system. It is therefore worth asking ourselves why we should be concerned about events that, on average, have a relatively small effect. We argue that the answer to this question may be with the risk attitude of electricity consumers and policy makers (and therefore network planners too, who somehow "serve" both). In fact, as suggested by empirical evidence, customers and policy makers generally dislike the risks associated with the highly adverse consequences often linked to HILP events and would thus like to reduce them as much as possible. But how can we model this risk attitude, and what is the underlying risk-attitude assumption in the aforementioned probabilistic assessment?

In risk analysis, attitudes toward risk are usually classified into three categories, which we describe in this section. Consider an electricity consumer who is given the choice between the following two options. In the first option, the consumer pays US$90 for a network service that hardly ever fails, and, when it does, small amounts of energy are unserved, totalizing an associated expected cost of ENS

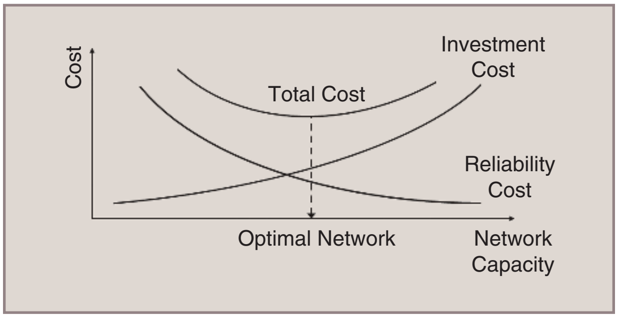

figure 1. The optimal balance between investment and reliability costs.

equal to US$10. In the second option, the consumer pays US$50 for a network service that fails more often and with larger amounts of ENS each time, totaling an associated expected cost equal to US$50. Note that, in both cases, the total amount paid by the consumer for the network and the EENS is the same. In this context, the consumer is said to be

- ✔ *risk neutral* if the consumer is indifferent to these two options
- ✔ *risk averse* if the consumer prefers the first option over the second one
- ✔ *risk seeking* if the consumer prefers the second option over the first one.

The reader can easily deduce that risk neutrality is intrinsically a part of traditional probabilistic analysis because the aforementioned two options seem equally attractive. In reality, however, consumers are typically risk averse and, arguably, prefer a more stable and predictable outcome from the electricity network, even if this may (slightly) increase cost, as mentioned previously. In fact, as in many other industries, consumers may be willing to pay the price of insurance policies that eliminate (or at least mitigate) the losses associated with some rare but high-impact scenarios that may occur. In this context, risk-averse electricity consumers (which we argue represent the majority) may prefer to be hedged against the consequences of HILP events on their electricity supply and pay for the corresponding cost increase even if these events occur rarely or may not happen at all.

Apart from very extreme cases such as earthquakes, which may be life-threatening and for which higher risk aversion may be justified for different reasons in any case, evidence of such a consumer attitude can be seen more and more often even for relatively smaller-impact events. For example, heat waves in Australia in January 2019 led to sporadic, rolling load-shedding events in several areas, including central Melbourne. The relatively short outages were considered outrageous by many consumers, even though they experienced only a minor overall adverse impact.

In addition to consumer attitudes, governments must consider the welfare of their citizens and, understandably, may want to take a risk-averse approach in dealing with HILP events for political reasons, irrespective of the classical economics associated with traditional power system planning methodologies. That is why specific regulatory and market mechanism responses were called for following the South Australia black system event of September 2016, and more are expected in response to the bushfires that occurred again throughout Australia in January 2020. In any case, once again, the main message here is that the risk-averse approaches and metrics that should be contemplated for HILP events are typically not present in current system planning practices.

Recognizing the Outage-and-Restoration Evolution: The Need for Time Domain Modeling

One important aspect of resilience is its time-varying nature. The concept of resilience includes the phases before and during a severe event as well as after the event, when the system recovers. In this context, Figure 2 shows the time-varying, multiphase resilience trapezoid, which clearly highlights the phases of a power system when exposed to extreme events,

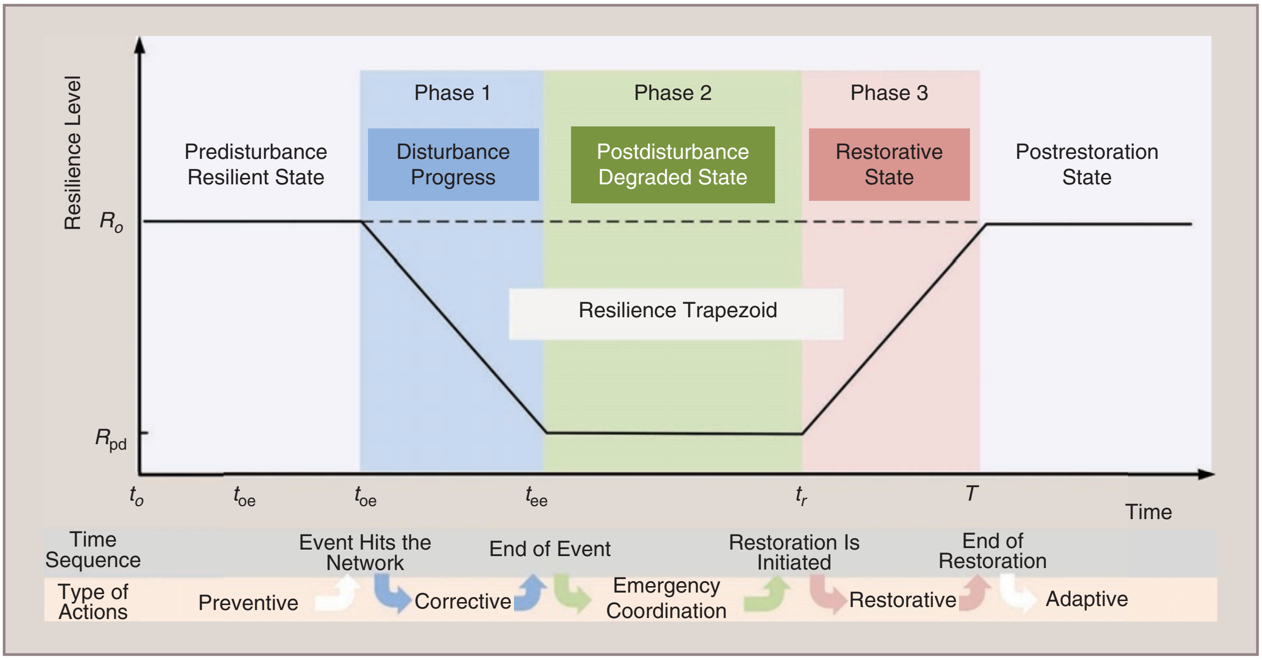

figure 2. A time-varying, multiphase resilience trapezoid. (Source: Panteli et al.)

namely, the predisturbance resilient state, disturbance progress, postdisturbance degraded state, restorative state, and postrestoration state. It also plainly highlights the type of actions that can be applied for mitigating the impacts of extreme events during these phases, such as preventive, corrective, emergency coordination, restorative, and adaptive. However, this critical temporal evolution aspect is usually missing in current reliability assessments for planning purposes, which mainly focus on the system response before and right after the disturbance occurs (without including system restoration).

In contrast, because the impact on the system due to an HILP event is substantial, the explicit modeling of the system response and restoration is key in assessing different options for enhancing resilience at the planning stage, especially those based on flexible and operational non-network solutions. This time-varying characterization also enables the modeling-targeted optimization of metrics specifically designed for resilience-analysis purposes, thus providing decision makers with the opportunity to select specific attributes of resilience that can be enhanced by implementing different operational and investment decisions, which also correspond to different enhancement propositions.

Probabilistic Risk-Averse Framework to Identify Resilient Network-Enhancement Options

Based on the aforementioned premises, we introduce a resilience-oriented planning methodology based on a stochastic, risk-averse, mathematical program for supporting the decision-making process of identifying resilient network enhancements. In the first stage, the proposed two-stage model (Figure 3) intelligently selects specific network investments from a set of candidate options, which are, in the second stage, tested through the quantification of their resilience benefits in probabilistic outage scenarios originated by stochastic simulation of natural hazards. As a result, the optimal portfolio of network investment decisions as evaluated through a given resilience metric (measured across various scenarios) is identified.

The stochastic generation and assessment of hazard and outage scenarios are carried out through the following simulation-based steps:

1) *Hazard characterization*: In the first step, we generate various hazards with random magnitudes and locations (this can be done by respecting historical patterns). Additionally, spatiotemporal profiles may be necessary to model hazards that change position and intensity dynamically (e.g., storms), spread (bushfires), or attenuate their magnitude with distance (earthquakes).
2) *Vulnerability assessment of system components*: By using fragility curves (illustrated in Figure 4) that are assumed to be known for various natural hazards and system components, either through historical data or on the basis of engineering modeling, we determine both 1) the hazard-dependent failure probabilities of every network component (e.g., towers and lines as well as substation and generation equipment) and 2) the outage scenarios across the system, which are generated from these probabilities.
3) *System response*: This is the step where we simulate, for each outage scenario identified above, the potential system cascading from automatic power flow rerouting, load/generation disconnection, and postcontingency redispatch (once cascading has ended). We then assess the spatially resolved volumes of energy not supplied. Importantly, prior to the outage, we assume a normal operation of the system by running an economic dispatch problem in which the system infrastructure is intact.
4) *System restoration*: We simulate both a) the reconnection of failed/damaged network components once these have been repaired (whose reconnection times are determined probabilistically assuming that the reconnection events are exponentially distributed) and b) the reconnection of load/generation, which is obtained using a postcontingency dispatch model.

Figure 5 illustrates the aforementioned process, and Figure 6 shows a typical curve for the supplied demand, which results from the simulation of the postfault events

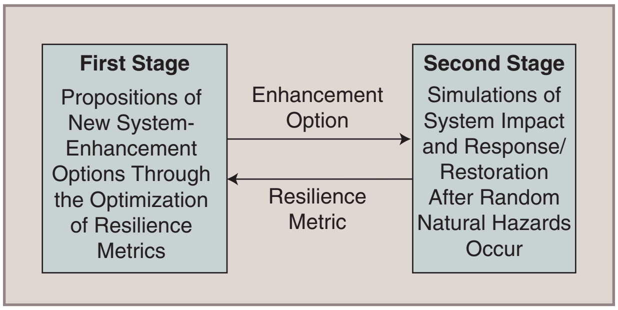

figure 3. The quantitative approach used to identify optimal resilient system-enhancement options. (Source: Lagos et al.)

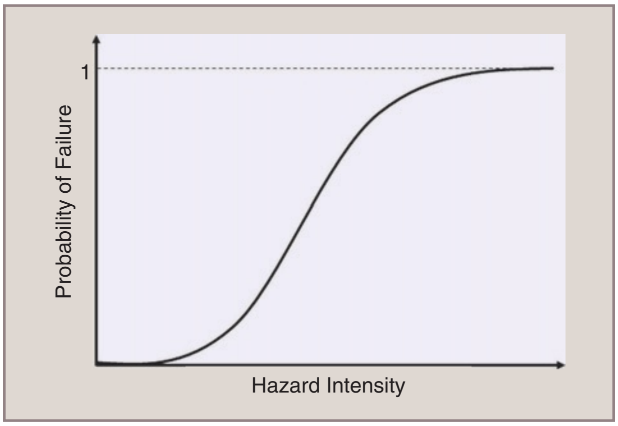

figure 4. An example of a generic fragility curve for a piece of network equipment.

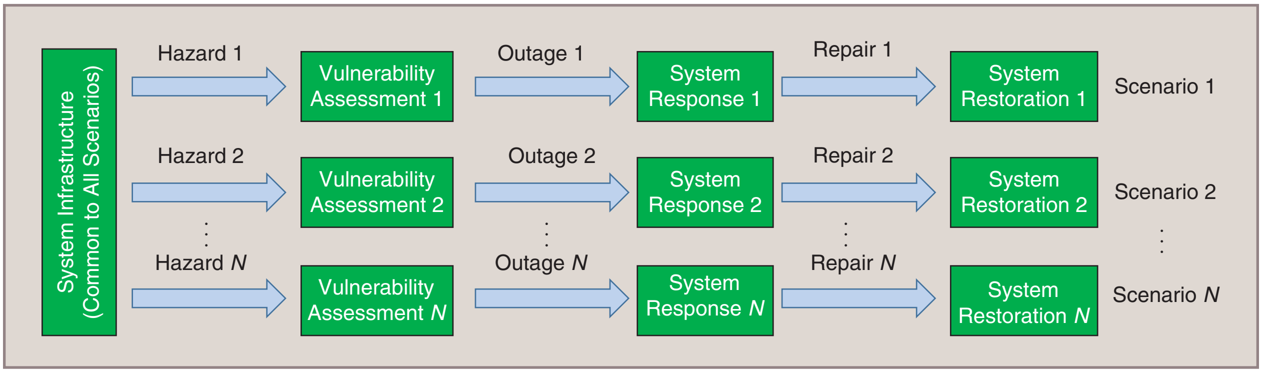

figure 5. A simulation of hazard-outage-repair scenarios for the system infrastructure under study.

associated with a scenario that follows this sequence: the random generation of a) hazards, b) network outages, and c) equipment repairs. Note that the shape of the curve in Figure 6 can vary and be hazard and system specific. This power supply curve is generated several thousands of times (e.g., 10,000) for different hazard-outage-repair sequences by using a Monte Carlo simulation. We consider a large number of simulations to adequately capture the potential consequences of a comprehensive set of natural hazards on the power network.

After the simulations have been performed under several outage scenarios caused by natural hazards, a suitable resilience metric can be selected and calculated for every scenario. The metric could, for example, be the ENS or, based on our previous work, one taken from the FLEP resilience metric system [the FLEP metric assesses how fast resilience drops (*F*-metric), how low resilience drops (*L*-metric), how extensive is the postdisturbance degraded state (*E*-metric), and how promptly the system recovers (*P*-metric)]. After quantifying the effect of each scenario using the selected metric, the optimization problem minimizes risk exposure subject to a budget constraint (representing the total amount available to be invested in resilient network enhancement), thus identifying the optimal portfolio of investment decisions that provides the best hedge against the HILP events simulated. The risk measurement being minimized can be determined by calculating the expected value of the selected resilience metric (e.g., ENS) across an appropriately selected worst set of scenarios resulting from the stochastic simulation.

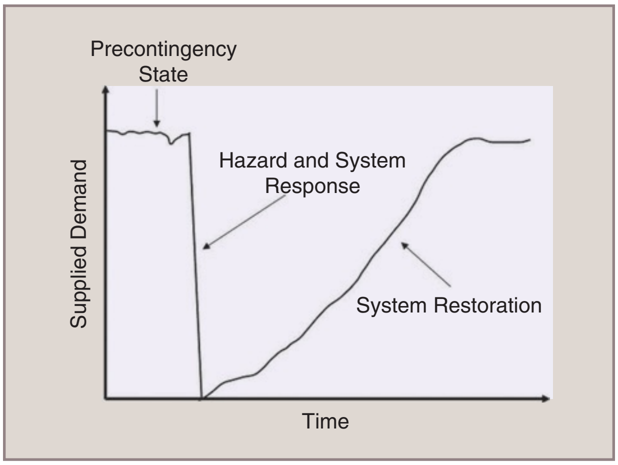

figure 6. An example of supplied demand curve resulting from each scenario simulated.

To do so, the conditional value at risk (CVaR) measurement can be used to consider only those scenarios representing the worst cases. More specifically, CVaR (also referred to as CVaR_α, although in this article, we use CVaR without the subscript to simplify the notation) represents the expected value across a predetermined set of worst cases. An illustrative example of a probability distribution function (PDF) and its relevant parameters, with the ENS used as the resilience metric, is shown in Figure 7. It should be noted that the value of the parameter α also provides an explicit indication of risk attitude, because $1-\alpha$ indicates the size of the considered set of worst cases. A reliability assessment would use the measurement of the EENS by sampling across all of the sets of outages. In this averaging, the impact of noncredible worst-case outages would normally be outweighed by the much more frequent credible outages. In some reliability assessments, the consideration of noncredible worst-case outages may even be ignored.

In the context of our framework then, this means that, in the first approximation, the mean value (i.e., the EENS) and the CVaR of the PDF shown in Figure 7 could be used as the reliability assessment and the resilience assessment measures, respectively. Furthermore, although optimizing for the EENS/CVaR is useful to clearly identify decisions from a reliability/resilience perspective, in practical settings, where planners need to consider both criteria to make tradeoff decisions, optimizing on a linear combination of the EENS and CVaR may also be a suitable option.

The proposed mathematical framework can be used to select a wide-ranging portfolio of resilient network-enhancement options depending on the specific decision variables considered in the problem, such as hardening infrastructure, the installation of new assets, a provision of better response times for repairing damaged infrastructure, restoring power, and so forth. This addresses the so-called resilience trilemma, that is, the need for balancing the portfolio solution among several options to make the system stronger, bigger, and/or smarter in a resilient and cost-efficient manner. In particular, among the set of investment decisions used to enhance system resilience, the following could be considered:

- ✔ new lines and transformers to create alternative routes to transfer power and provide redundancy or additional reactive power to operate the network under weaker conditions when several network assets are outaged due to HILP events
- ✔ substation, tower, and other equipment hardening to make the system more robust and stronger against HILP events (this is modeled by shifting fragility curves to the right)
- ✔ shorten response times by increasing expenditures in enhanced stocks of network assets and equipment, more repair crews, and more online monitoring and control solutions
- ✔ the installation of new flexible network technologies such as special protection schemes, energy storage units, flexible alternating current transmission systems, high-voltage dc (HVdc), and so on to make the system more flexible to adapt to different conditions' postfault, helping to mitigate the consequences of HILP events
- ✔ the installation of distributed energy resources (such as microgrids, distributed generation, and so on) to provide localized energy solutions when the main system fails.

There are several ways to apply this framework, especially to implement the two stages illustrated in Figure 3, by using mathematical programming methodologies. For the analysis in this article, we used optimization via simulation (OvS) techniques. These techniques determine the (nearly) optimal portfolio of network enhancements based on a series of simulations. More specifically, from the perspective of the optimizer, which is the first stage, the simulator, which is the second stage, is assumed to be a black-box model without a known mathematical structure. One of the key advantages of the OvS approach is that it allows for the inclusion of a great deal of operational details in the simulation stage, e.g., minimum stable generation levels, ramp rate limits, minimum startup and shutdown times, and so on, which require a nonconvex formulation and are complex and hard to manage in closed form.

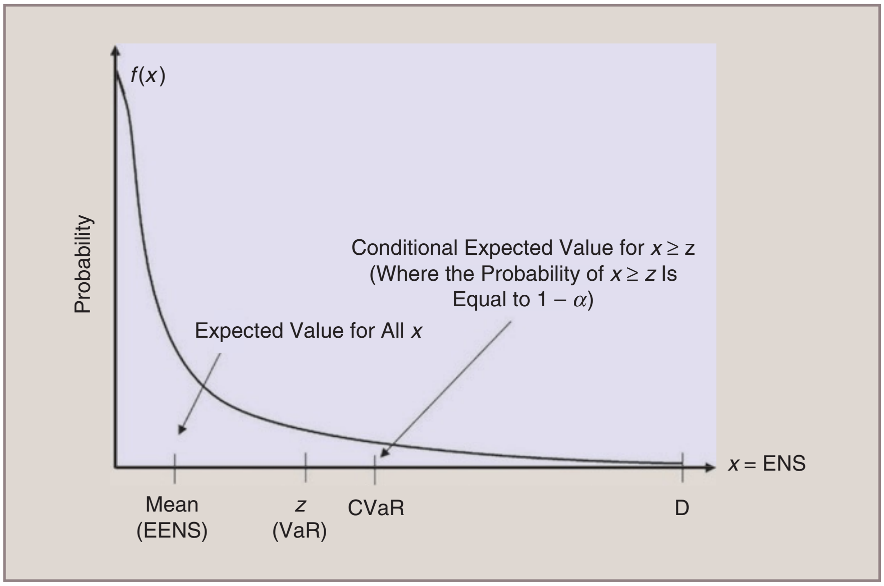

figure 7. A CVaR concept for risk-averse resilience assessment, where $1-\alpha$ indicates the size of the considered set of worst cases. D indicates total demand.

Illustrative Two-Busbar Example

Textbook Illustrative Case Study

This simple example illustrates and demonstrates our proposed framework, which identifies resilient enhancement options against HILP events in network planning and, crucially, how these differ from other decisions that are more reliability oriented. The two-busbar network in Figure 8 features one 500-MW generating unit in node 1, one load in node 2 with a constant demand of 500 MW, and a transmission link between the two nodes. Depending on the configuration (i.e., the number of circuits and their capacities) and reliability characteristics of this link and assuming perfect reliability for the generator, this power network can be adequate, secure, and/or resilient. As adequacy and security have historically been a part of reliability analysis, we will consider a network to be reliable if it is both adequate and secure. We also use the dc power flow approximation for the sake of simplicity.

Reliability 1: Adequacy

Considering that adequacy is the ability of a power system (including generation and network capacities) to supply the

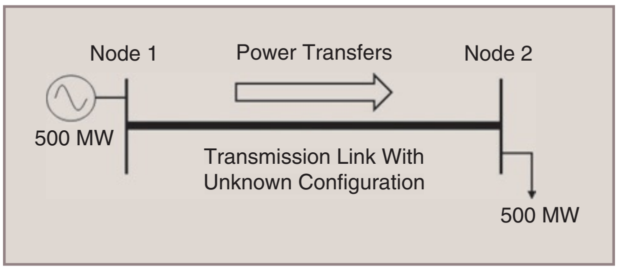

figure 8. The illustrative two-busbar system.

> In reality, however, consumers are typically risk averse and, arguably, prefer a more stable and predictable outcome from the electricity network, even if this may (slightly) increase costs.

aggregate electricity demand at all times, the power network in Figure 8 is adequate if the total (thermal) capacity of the link is at least 500 MW. This can be achieved by a number of network configurations, including the option of one single circuit of 500 MW transferring power from node 1 to node 2. This particular option, however, is evidently not *N*–1 secure.

Reliability 2: Security

From our previous work, we distinguish between two types of security: deterministic *N*–*k* security and probabilistic security. To comply with a deterministic *N*–1 security standard for network design, we need two circuits, each of (at least) 500 MW to link nodes 1 and 2. A probabilistic standard, instead, demands an appropriate balance between the cost of improving reliability, here in the form of investment costs, and the associated savings in reliability operational costs, measured through the improvement in the EENS (resulting from the new investment) × the VoLL. Let us now assume that there are only two possible "secure" configurations (i.e., the number of circuits and their capacities) for the transmission link in question, and let us evaluate the cost and benefits of each of them to identify the appropriate optimal solution. Table 1 provides the basic reliability information and costs of the following two alternatives:

- ✔ *N–0 option*: where two circuits of 250 MW are installed
- ✔ *N–1 option*: where two circuits of 500 MW are installed.

In both cases, the network has fully available capacity 99.976% of the time (further reliability information associated with outage and repair rates is presented in Table 2). In this case, the *N*–0 solution is determined to be more economically efficient and therefore should be the one selected under a probabilistic security approach; however, this solution is sensitive to an array of economic and reliability parameters. For example, if the VoLL is increased from US$1,000/MWh to US$30,000/MWh, then the secure option changes from the *N*–0 to the *N*–1 design solution.

Resilience

One of the key characteristics of the probabilistic security analysis carried out in the previous section is its focus on the EENS, which, as discussed, is not suitable for resilience studies dealing with HILP events. For the purpose of assessing resilience then, let us assume that the (marginal) probabilities of the four states previously evaluated (a no-fault state, two single-fault states, and a double-fault state) originate from the conditional probabilities displayed in Table 2. More specifically, Table 2 shows the probability of the four states under two different weather conditions, namely, fair and adverse weather, as well as the marginal probability of the four states considering both weather conditions.

For illustrative purposes, we assume that the failure rate is 100-times higher for adverse weather and that repair times increase from 4 h under fair weather conditions i.e., a repair rate of 2,190 occurrence per year (occ/y), to seven days under adverse weather conditions (i.e., a repair rate of 52 occ/y). Also, adverse weather, in this example, is limited to 1 h per year (thus conventionally representing an HILP event), while fair weather conditions occur during the remaining time (i.e., 8,759 h).

To provide a hedge against such an HILP event, we analyze the following three options within the concept of a resilience trilemma (assuming that the initial condition is the same *N*–0 network configuration selected under the probabilistic security approach described in the previous section):

- ✔ *N–1 design*: where we re-evaluate the option to install two circuits of 500 MW, i.e., making the network "bigger" by adding redundancy
- ✔ *N–0 with shorter response times under extreme events*: where we evaluate a contract with other network companies to use their repair crews under extreme events, which reduces the repair times from seven to three days (i.e., making the network "smarter")
- ✔ *N–0 with underground cables*: where we evaluate the option to bury the current double circuits, each with 250 MW of capacity, thus halving the failure rate under both weather conditions, and assuming at the same time, for simplicity, that the repair rate stays the same. This is equivalent to a "stronger" system option.

Table 3 shows the impact of these new options on various average and risk indicators, including

- ✔ the EENS of the ENS across all scenarios (economically valued at the VoLL)
- ✔ the CVaR of the ENS, that is, the average ENS across the 0.001% worst cases (economically valued at the VoLL)
- ✔ the probability of a double outage under adverse weather conditions, which occurs for 1 h per year only.

As can be expected, changing the network design from *N*–0 to *N*–1 provides the best results in terms of the EENS cost, reducing it by 93% from approximately US$539,000 per year to US$38,000 per year. However, this decision provides a very limited hedge against HILP events, reducing the CVaR by only 6% from US$4,113,000 per year to US$3,846,000 per year. (Note that, in this case and the following ones, the probability of a double outage and the CVaR follow a similar pattern, so for the sake of simplicity, we focus just on the CVaR.) Interestingly, reducing the repair time under adverse weather reduces the CVaR significantly (by 35%, from US$4,113,000 per year to US$2,690,000 per year) while the corresponding EENS reduction is more limited (by only 13%). This exemplifies the fact that one enhancement solution may be preferred from a reliability perspective, while, from a resilience perspective, other options may be more attractive.

Remarkably, the option in which lines are underground features an attractive compromise between reliability and resilience indicators, reducing the EENS cost by 48% (which is not as good as the 93% reduction related to the *N*–1 solution but not as bad as the 13% reduction related to the *N*–0 case with shorter response times) and reducing the CVaR by 31% (which is not as good as the 35% reduction related to the *N*–0 case with shorter response time but not as bad as the 6% reduction associated with the *N*–1 solution). This is

table 1. The reliability and cost information associated with two alternative network design options.

Option *N*–0						
Cost of Investment Calculation						
Unit cost of investment (US$/MW per km per year)	100					
Length (km)	200					
Capacity per circuit (MW)	250					
Number of circuits	2					
Cost of investment (US$)	**10 million**					
Cost of the EENS Calculation		**Circuit 1**	**Circuit 2**	**State Probability**	**Available Capacity (MW)**	**Power Not Supplied (MW)**
VoLL (US$/MWh)	1,000	Available	Available	0.9997629	500	0
Expected power not supplied (MW)	0.06148	Unavailable	Available	0.0001142	250	250
Time horizon (h)	8,760	Available	Unavailable	0.0001142	250	250
Cost of the EENS (US$)	**538,532**	Unavailable	Unavailable	8.782E-06	0	500
Total cost calculation						
Total cost (US$)	**10,538,532**					
Option *N*–1						
Cost of Investment Calculation						
Unit cost of investments (US$/MW per km per year)	100					
Length (km)	200					
Capacity per circuit (MW)	500					
Number of circuits	2					
Cost of investment (US$)	**20 million**					
Cost of the EENS Calculation		**Circuit 1**	**Circuit 2**	**State Probability**	**Available Capacity (MW)**	**Power Not Supplied (MW)**
VoLL (US$/MWh)	1,000	Available	Available	0.9997629	1,000	0
Expected power not supplied (MW)	0.00439	Unavailable	Available	0.0001142	500	0
Time horizon (h)	8,760	Available	Unavailable	0.0001142	500	0
Cost of the EENS (US$)	**38,464**	Unavailable	Unavailable	8.782E-06	0	500
Total cost calculation						
Total cost (US$)	**20,038,464**					

particularly important in practice in the presence of budget constraints and under the need for undertaking both reliable and resilient enhancements in power networks.

Realistic Application to Earthquakes in Chile

To demonstrate the applicability of the proposed resilience-planning framework to the real world, the following case study is used to identify resilience-enhancement decisions among an array of multiple candidate solutions to protect against earthquakes in the Chilean transmission system.

Case Study Description

The Chilean transmission system, which covers more than 3,200 km from Arica to Chiloe, is modeled through an equivalent network composed of 40 nodes/substations and 56 transmission corridors (shown in Figure 9), representing its infrastructure in 2018. For that year, electricity demand was approximately 76 TWh, and generation supply included mainly hydro [23 TWh (30%)], coal [30 TWh (39%)], and gas [11 TWh (15%)] units, with minor participation from wind [4 TWh (5%)] and solar resources [5 TWh (7%)]. The total installed generation capacity was 24 GW.

To model the potential failure of system infrastructure during an earthquake, we used the fragility curves of towers, generation units, and substations adopted by the U.S. Federal Emergency Management Agency (Hazus-MH2.1), which relates the probability of failure of these system components with the peak ground acceleration (PGA) at their particular locations.

To calculate the PGA in different locations following an earthquake with a given epicenter, we used validated models capable of characterizing the strong ground-motion attributes observed in the 2010 Chilean earthquake.

We then randomly generated a comprehensive set of scenarios (e.g., 10,000), which follows this sequence.

1) *The random generation of earthquakes and the PGA calculation*: Using a random location and a fixed intensity equal to 8.5 Mw, equalizing the conditions of the most recent 2010 earthquake (which was one of the worst earthquakes experienced in Chile), the PGA is determined at the location of each system equipment.
2) *The random generation of network outage*: Once the probabilities of outages are obtained from the fragility curves, outages are simulated through a Monte Carlo simulation.
3) *The random generation of equipment repairs*: Once pieces of equipment fail, they are recovered by following a random process.

The system dispatch before, during, and after the earthquake was obtained by simulating five days, where the earthquake occurs in the first hour to capture the system collapse as well as the system recovery. The analysis captures key features of a resilient power grid.

Results: Portfolio Solutions for Resilience Enhancement

Figure 10 shows the Pareto frontier between the risk measurement and the budget used to improve resilience. Here, the risk measurement is the conditional EENS (CEENS), where the ENS is averaged across worst-case scenarios, e.g., all the scenarios originated by very large earthquakes with a magnitude of 8.8 Mw (in practice, we can assume that the CEENS ≈ the CVaR by an appropriate selection of the value

table 2. The reliability data and probabilities of failure under fair and adverse weather, and the marginal probabilities of failure for the four states considered.

	Fair Weather	Adverse Weather
Failure rate (occ/y)	0.2	20
Repair rate (occ/y)	2,190	52
Unavailability	9.1E-05	0.27723
Availability	0.99991	0.72277
Duration (h)	8,759	1

Circuit 1	Circuit 2	State Probability	Available Capacity (MW)	Power Not Supplied (MW)
Available	Available	0.999817	0.5224	0.999763
Unavailable	Available	9.13E-05	0.200373	0.000114
Available	Unavailable	9.13E-05	0.200373	0.000114
Unavailable	Unavailable	8.34E-09	0.76855	8.78E-06

occ/y: occurrence per year.

table 3. The average and risk indicators of the four considered network design options.

Metric	*N*–0 Base Case	*N*–1	*N*–0 Shorter Repair Time	*N*–0 Underground
VoLL × EENS (US$)	538,532	38,464	470,506	280,428
VoLL × CVaR (US$)	4,113,206,199	3,846,412,398	2,690,095,838	2,837,833,988
Probability of double outage under adverse weather (%)	7.7	7.7	2	2.6

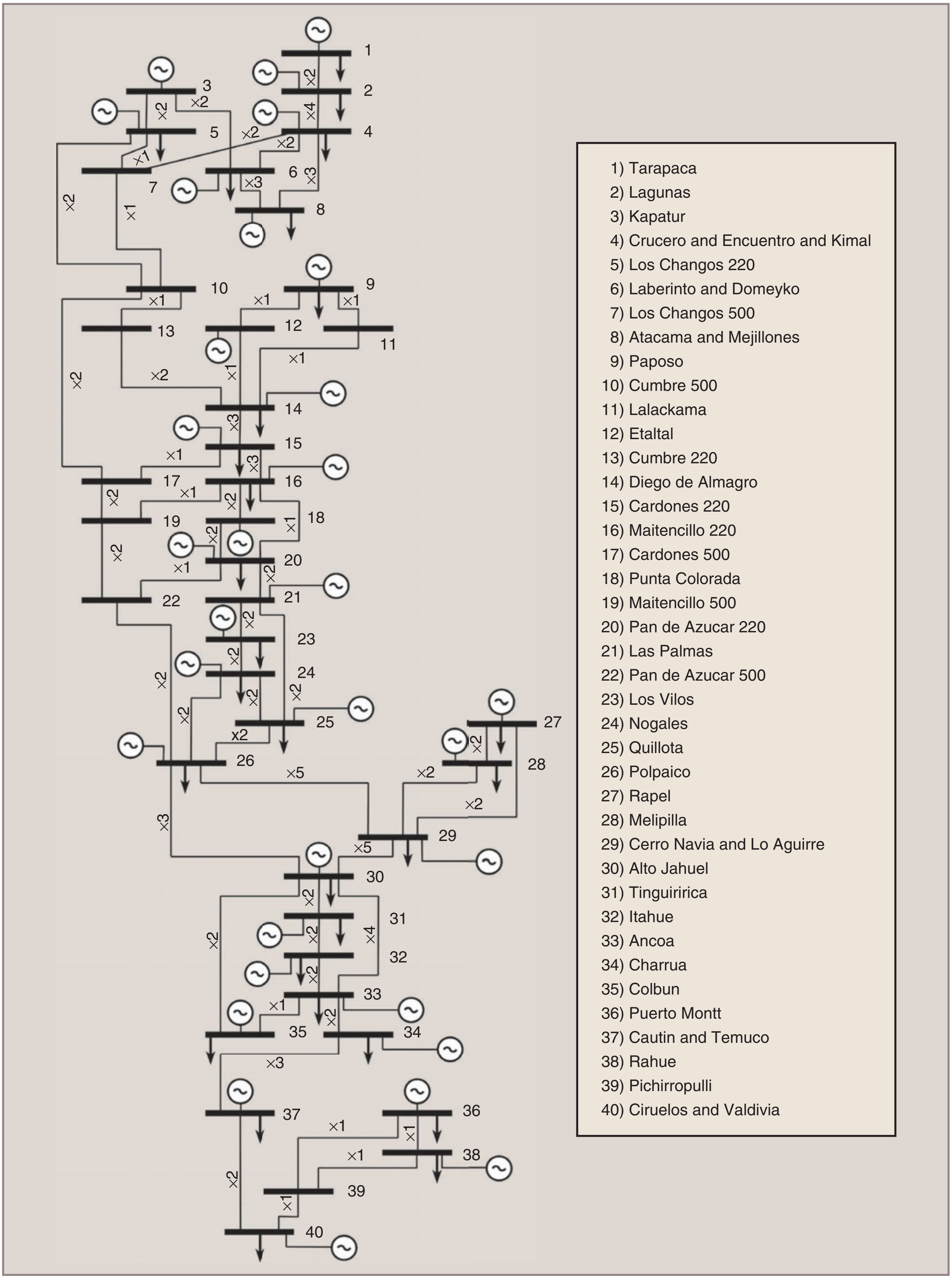

figure 9. The Chilean transmission network model used in the case study, indicating topology, generation and demand nodes, and the number of circuits per corridor.

> This exemplifies the fact that one enhancement solution may be preferred from a reliability perspective, while, from a resilience perspective, other options may be more attractive.

of the parameter α), and the "budget" indicates the number of available investment options allowed as a proxy for their total cost (e.g., budgets equal to one, three, and five mean that up to one, three, and five investment decisions can be made, respectively). The figure shows the most economical option (a budget equal to one) is to invest in an HVdc link connected point to point between the Atacama Desert (node 4) and Santiago (node 29). In fact, this enhancement option features two main characteristics.

First, pre- and postfault power flows are fully dispatchable due to power electronics equipment that allows system operators to have a higher level of controllability of the power flows, co-optimizing them with other operational measures, e.g., generation (re)dispatch, the exercise of reserve services, and so forth. The second characteristic is the unique topological connection of this candidate link, which bypasses most substations between the north and the center of the country, reducing, in this way, its exposure to earthquakes (note that the main impact from earthquakes is on substation equipment rather than towers and transmission lines).

In fact, empirical evidence from past events in Chile strongly suggests that substations (rather than lines) experience the most severe problems during earthquakes. For example, in the 8.8-Mw earthquake in 2010, only three towers failed, while 12 (out of 46) substations in high-voltage transmission systems showed some level of damage. For this very same reason, the best complements for this HVdc link are the hardening of substations supplying Santiago, i.e., Alto Jahuel and Cerro Navia (a budget equal to three).

Interestingly, for a budget equal to five, two storage facilities, each a pumped-hydro storage unit of 300 MW, are added to the optimal portfolio. In this case, the storage facilities located in Cumbre and Lagunas allow the system operator to more efficiently manage the large amounts of renewable generation located in the north (under any outage conditions, with and without earthquakes), whose production is transferred through the HVdc link to the central area of the country in Santiago, which is, in turn, supplied by the Cerro Navia and Alto Jahuel substations (among others). All of the aforementioned assets are part of the selected portfolio solution, clearly indicating the value of coordinated investment. These five enhancement options selected as a unified portfolio thus act as one synergic multiasset enhancement, providing the best feasible insurance to the main system load center against the occurrence of large earthquakes.

Summary and the Way Forward

In the context of the transition from reliable to resilient power grids, we have demonstrated the need for considering risk-based (rather than average) indicators to identify the necessary enhancements in network and system infrastructure. Importantly, in this article, we discussed some of the fundamental differences among various investment solutions (e.g., redundancy and substation hardening) compared to more flexible operational solutions, with the overall aim of improving the reliability and resilience of power grids. Although the proposed mathematical framework used to determine resilience network enhancements is fully probabilistic, this differs from the classical probabilistic-based decision-making models due to the explicit incorporation of risk aversion, in contrast to the risk-neutral attitude assumed in classical reliability studies. We argue that planning for resilience corresponds to becoming risk averse so that the resulting network designs are less exposed to HILP events in comparison to designs resulting from (risk neutral or even simply risk unaware) reliability studies.

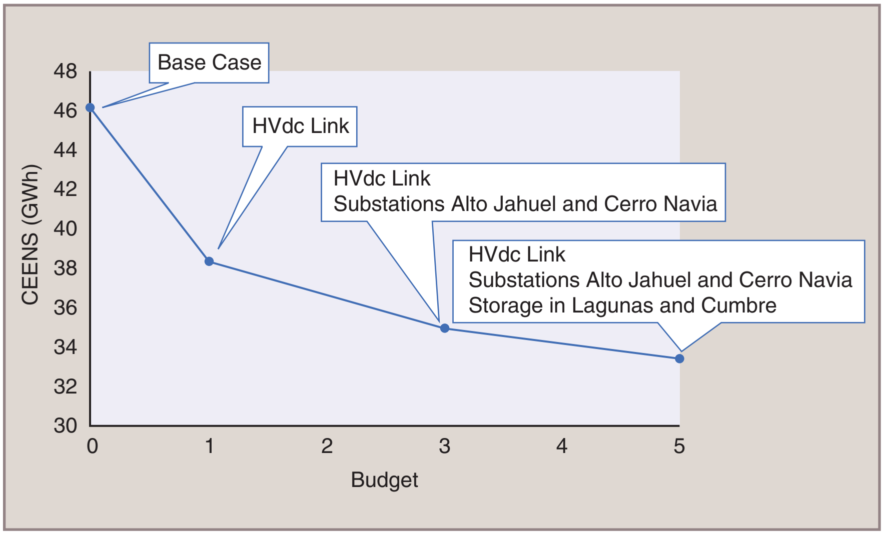

figure 10. The optimal portfolio solutions for resilience enhancement for different budgets. CEENS: conditional EENS.

> We have demonstrated the need for considering risk-based (rather than average) indicators to identify the necessary enhancements in network and system infrastructure.

The differences between reliability- and resilience-driven investments were illustrated on both a simple textbook, two-node example and a realistic 40-node representation of the Chilean power system. Although the former was used to clearly explain the fundamental concepts of the framework we proposed, in the latter, we identified and discussed the best Pareto portfolios of investment propositions that offer the highest level of hedge against the adverse impacts of large earthquakes. For this case, we also emphasized the importance of hardening the infrastructure beyond the classical redundancy-based (i.e., adding more and more infrastructure), reliability-driven solutions. Furthermore, we demonstrated how redundancy effectively improves average indicators, while hardening improves risk indicators. Perhaps most importantly, our results also clearly illustrated how additional operational flexibility and responsiveness can play a major role in enhancing system resilience to HILP events.

Looking ahead, for planners and regulators to fully consider resilience-enhancement investment solutions once specific hazards or potential HILP events of interest have been identified (which is a nontrivial and case-specific exercise per se), the following two questions will need to be more appropriately addressed in the near future:

1) What is the right level of risk mitigation for HILP events? Or in other words, what is the right level of risk aversion to be considered when determining resilience-based investment propositions?
2) How should the costs associated with resilience be allocated among market participants?

Although the latter may arguably be more intuitive to address, for example on a beneficiary-pays basis (i.e., identifying the set of beneficiaries associated with the resilient network enhancements), the former undoubtedly requires a deeper understanding of electricity consumers' risk attitudes. This is not an easy task and goes beyond the expertise of many members of our IEEE PES community, critically demonstrating, going forward, the need for undertaking and integrating more interdisciplinary work in this field.

For Further Reading

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Blackouts, Restoration, and Islanding

A System Resilience Perspective

By Martin Braun, Christian Hachmann, and Jonas Haack

THE RESILIENCE (OR RESILIENCY) OF A SYSTEM IS characterized by its resistive, anticipative, absorptive, adaptive, and restorative capacities when facing adverse events. Resilience is an umbrella term that goes beyond related concepts like robustness and protection, redundancy and fallback options, or reliability. A system is considered resilient when it can provide a high level of service, even after high-impact, low-probability events. For every system, resilience regarding a specific event can be analyzed by studying the system's performance over time.

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The overall resilience is the aggregation of system performance over all possible adverse events. Obviously, it cannot be calculated as a precise number given the lack of knowledge of all relevant types of events and their probabilities. However, analyzing specific events allows for a qualitative comparison of the relative resilience impact of certain measures and approaches for improvement.

Application of Resilience Metrics for Power System Restoration

In the autumn of 2005, there was a major outage in a part of the German distribution system the like of which had not occurred for decades. It was caused by an extreme weather situation. Beginning in the morning of 25 November and increasing throughout the day, heavy snow and ice cover accumulated on overhead lines. In combination with unfavorable wind, multiple pylons of the 110-kV high-voltage (HV) network and hundreds of pylons within the medium-voltage (MV) network failed, causing an outage that affected up to 250,000 people in 25 municipalities. It took more than four days until all customers were reconnected to the power system. Due to the high number of destroyed lines, it was not possible to reconnect all loads by means of the existing infrastructure. Mobile emergency supply diesel generators as well as provisional lines had to be brought into the region.

Figure 1 shows a schematic of the incident relating the events to common resilience terms. The timestamp t_e marks the onset of the adverse event. After t_e, in the first hours of the extreme weather event, when ice acumulated on the overhead lines, the power system was able to "resist" due to the designed mechanical robustness. However, at t_1 the first overhead line failed. Therefore, the performance of the power system from the operators' point of view decreased. But due to N–1 contingency design (defined absorption capacity), the system was able to "absorb" this contingency. Consequently, the hard measure of system performance—supplied/unsupplied customers—was not yet reduced. Subsequent line failures exceeded the available absorption capacity, resulting in unsupplied customers. To resupply customers, emergency generators and provisional lines were brought to the region to "adapt" the damaged infrastructure, and after five days all customers were provisionally resupplied ($t = t_4$ in Figure 1). The system performance from the customers' point of view was restored as soon as they were resupplied.

In the terminology of power system operation, parts of the adaptive as well as the operation restoration phase are called *power system restoration* because it aims at resupplying all customers. However, from the operators' point of view, the provisional measures represented a still-impaired state of the system, and it took much longer to "restore" the infrastructure and end the emergency service arrangements. After the complete reconstruction, on the other hand, the performance from this perspective was even better than before the adverse event. The components were not just replaced by equivalents but in some cases by more robust versions. Therefore, the infrastructure restoration and improvement phases overlap in the example. The indicator *power system performance* from an infrastructure perspective does not only include the indicator of "supplied customers" from a system operational perspective but also accounts for addtional criteria such as observability and operational reserves.

Today, this region contains a large amount of distributed generators (DGs), such as wind energy, photovoltaic (PV), and biomass plants. At many times, the available primary energy and distributed energy resources (DERs) could serve a significant share of the load. However, there is almost no islanding capability from the technical or the regulatory points of view. Additional communication infrastructure, grid-forming devices/controllers, and operational procedures would be

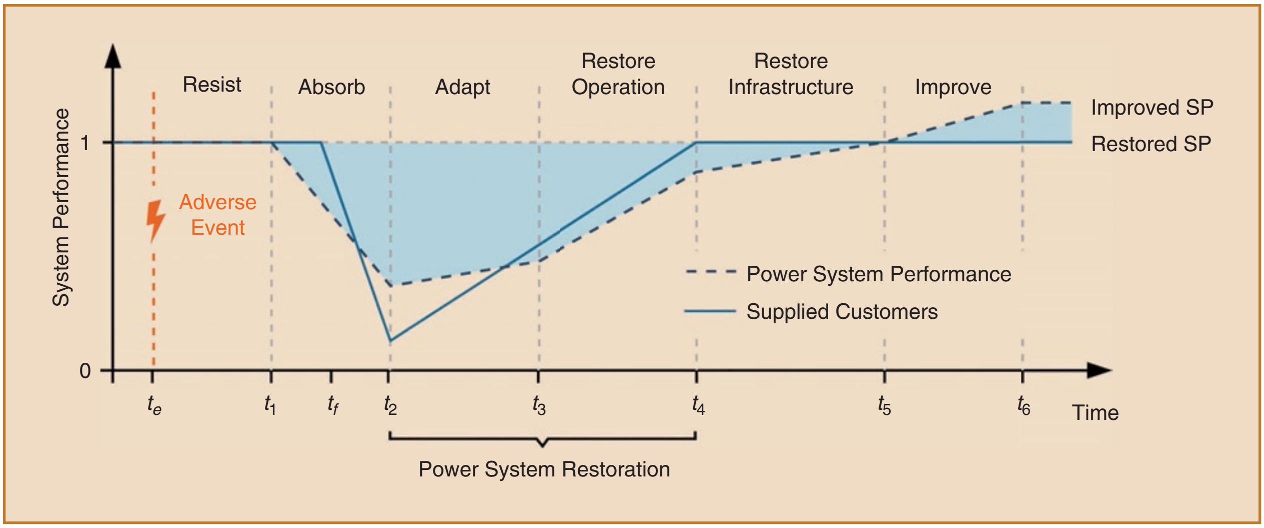

figure 1. The changes in system performance and supplied customers over time during an outage event, naming the resilience categories resist, absorb, adapt, restore, and improve. SP: system performance.

needed to enable flexible islanding of the renewable resources that would further increase resilience by decreasing the probability and duration of customers' outage times.

One challenge is to quantify the technical improvement of resilience in terms of reducing the probability and duration of unsupplied load by installing DG islanding capability. The evaluation of socioeconomic benefits and the justification of accompanying costs present challenges of their own. These technical and economical evaluation challenges and technical options are addressed later in this article.

Resilience: Beyond Reliability

Since it was first introduced to power systems by Holling in 1973, the concept of resilience has found its way from ecology into engineering. The focus has been on natural phenomena such as extreme weather events. Resilience, in contrast to reliability, deals with the long tail of high-impact/low-probability events. Figure 2 shows examples of such events, where the arrows indicate the various times between the first resupply and the final system restoration. Dotted lines show time spans when only a smaller section of the system was still unsupplied.

In contrast to these rare examples of blackout events, faults regularly occur in the power system that affect relatively few customers, normally only for seconds or minutes and very infrequently for a few hours. In Germany, for instance, about 150,000 interruptions that exceed 3 min for low-voltage (LV) end customers are registered annually. However, these large numbers only increase the System Average Interruption Duration Index (SAIDI) by approximately 2 min/year per end customer at the LV level. The total SAIDI is about 12–15 min/year, which does not consider extreme event (resilience-related) outages in these general reliability statistics.

Metrics in Power System Applications

The design and operation of power systems typically comply with the following priorities:

1) *Safety first:* Direct harm to the health or even life of humans is to be avoided.
2) *Damage protection:* The power system's components are to be protected from damage, i.e., components are allowed (sometimes even required) to disconnect instead of being destroyed (e.g., from an overload).
3) *Security of supply:* All customers must be supplied.
4) *Power system optimization:* The remaining flexibility allows optimizing power system operation regarding parameters such as cost-efficiency (e.g., economic dispatch), minimization of losses, increasing life expectancy of components, and so on.

Consumer Perspective

From a consumer perspective, the most relevant metric is the supply of load. Customer satisfaction is achieved when demand is met within secure boundaries of voltage and frequency where devices can operate without interruptions.

Operator Perspective

The power system operators' task of meeting customer requirements is fulfilled by controlling the voltages, frequencies, and currents within the grid under normal conditions. Technically, there is a huge degree of freedom when it comes to the operational strategies of dealing with power system phenomena that result from operation itself, like line switching or transformer tap changes, as well as from external effects, like lightning overvoltages or short circuits.

A grid operator normally would only supply consumers when a certain level of power quality can be guaranteed in terms of interruptions, frequency, and voltage stability. Therefore, in

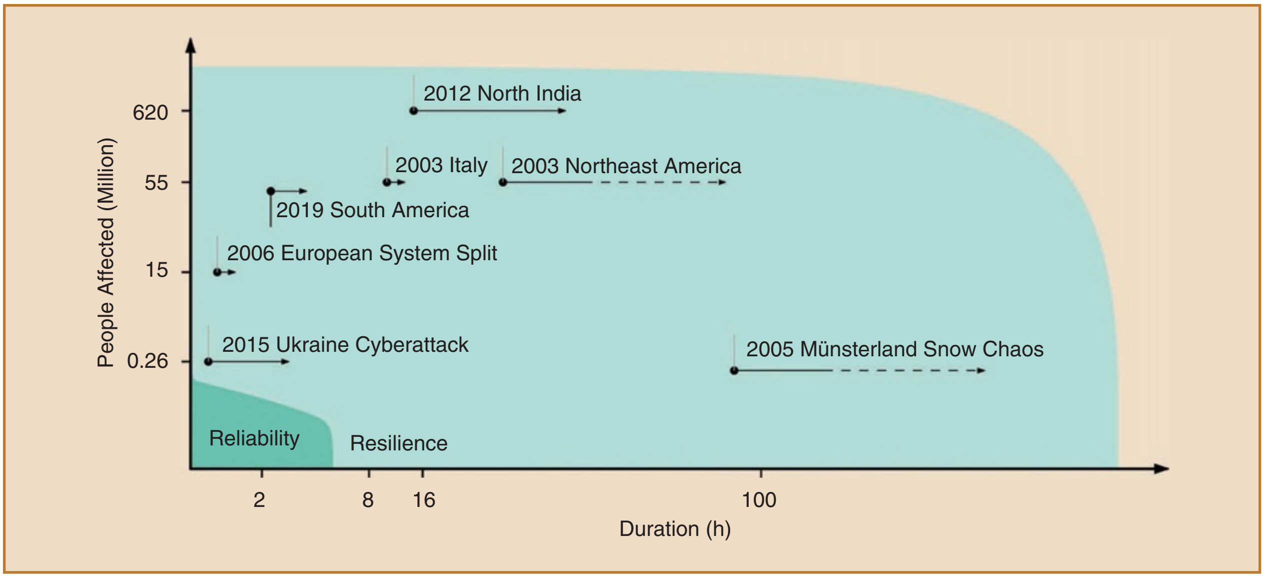

figure 2. Some examples of big blackouts and how to distinguish reliability from resilience.

terms of system performance, the power system distinguishes only between sections that operate within the limits of personal safety and prescribed power quality and sections that are disconnected (normally by protection schemes). In contrast to information and communication technology (ICT) systems, an electric power system is not operated in a way that offers severely impaired voltage quality (e.g., very low or very high voltages or frequencies) to a customer. In ICT systems, it is normal to accept reduced quality of service (QoS), such as longer latencies.

When faced with the challenge of quantifying the damage caused by a (partial) blackout, there are numerous approaches. Simple metrics are

- the overall duration of the outage
- the maximum loss of load
- the lost energy.

These metrics do, in fact, correlate with the overall loss of welfare. However, there are some additional aspects to consider.

- Some economic damage comes directly with the onset of a blackout. Processes are interrupted, production batches are lost, manual restarts required, and so on.
- If the duration of an outage is longer than the designs of backup systems for critical facilities, the damage is greatly increased. Furthermore, components of the power system might become unavailable over time when backup power runs out.
- Prolonged outages during very cold periods pose a special challenge since freezing can cause severe damage to customer property, such as water pipes and perishables. Moreover, they threaten components of the energy supply system, such as plants and heating networks.

Figure 3 presents a schematic view of the damage over different durations of time.

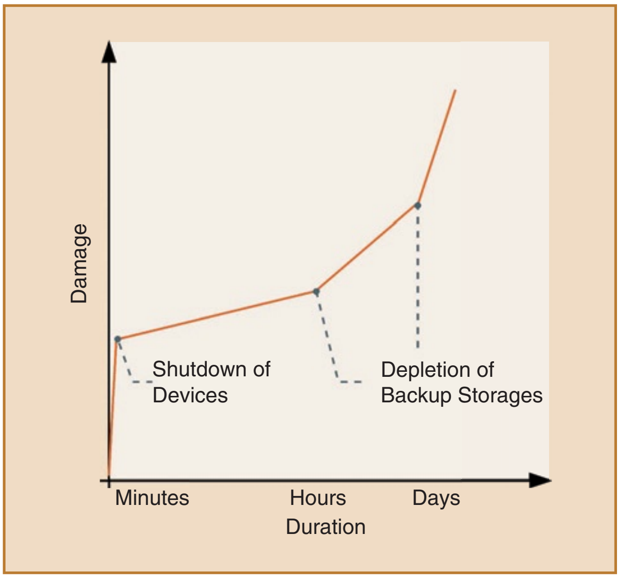

figure 3. The overall damage types of an outage.

Digitalization: The Transition to Cyberphysical Systems

Ongoing changes in power systems are driven by four major global trends: decarbonization, decentralization, autonomy, and digitalization. Decarbonization by renewable energy sources leads to a more sustainable energy supply structure that should be designed with at least the same level of resilience as the conventional fossil-based structure. Wind power plants, biomass plants, and especially millions of rooftop PV plants cause a decentralzation of power supply, shifting generation from the bulk system to the distribution system. In addition, electrical heat pumps and electric transportation provide further local/decentral electrical conversion approaches that allow higher efficiencies and decarbonization in all sectors. Including storage options in this perspective leads to another trend toward autonomy based on local/regional power generation, storage, and conversion technologies. A fourth trend is digitalization.

Digitalization of the power system is the connection of an increasing share of power system components to communication infrastructure and adding sensors, actors, and algorithms for more intelligent automation. The applied ICTs enable the coordination of DERs in more decentralized supply architectures. Digitalization also facilitates benefits in power system operation such as decentralized autonomy or operating the power system closer to its capacity limits. However, ICTs also add a vulnerability to power system infrastructure because technical systems may fail, and they may be corrupted or manipulated. Although secure power system operation becomes dependent on a secure ICT network, power system operation also affects the resilience of the ICT.

Figure 4 illustrates how hardware redundancies, additional sensors, actuators, and controllers via ICT complement the fundamental constituent of system performance: the supply of loads. The safety margin provides an additional operational indicator for the power system: the larger the safety margin, the more robust the power system operation is against possible adverse impacts.

Important questions should be answered.

- Does digitalization increase resilience due to better transparency and control capabilities?
- How can more complex cyberphysical infrastructures be designed to achieve higher resilience levels by digitalization, despite additional risks of cyberattacks or communication failures?
- ICT allows the system to operate more at the edge of capacity limits, whereas additional capacity raises the level of resilience. What is the right balance between reducing costs of power system reinforcements and reducing costs of high-impact/low-probability events?

ICT Resilience

The increasing interdependency of power systems and ICT adds a level of complexity to the analysis of the cyberphysical power system's resilience. ICT brings transparency and flexibility into power system operation that should increase the degree of power system resilience. However, ICT systems have vulnerabilities that can be expressed in terms of ICT resilience and its impact on power system resilience. In total, the cyberphysical power system resilience needs to be addressed.

The ICT system performance can be categorized into four states:

1) *Full QoS:* all connected nodes receive the information they require to work as expected in a timely manner
2) *Reduced QoS:* information and control signals arrive late or are lost when ICT is not fully available, meaning that a share of the nodes in the network is not connected to the ICT system any more
3) *No ICT:* a complete failure of the communication infrastructure; all power system components must operate in a fallback mode
4) *Corrupted ICT:* even worse than no ICT, malicious information and control signals arrive and make power system components act in an adverse manner.

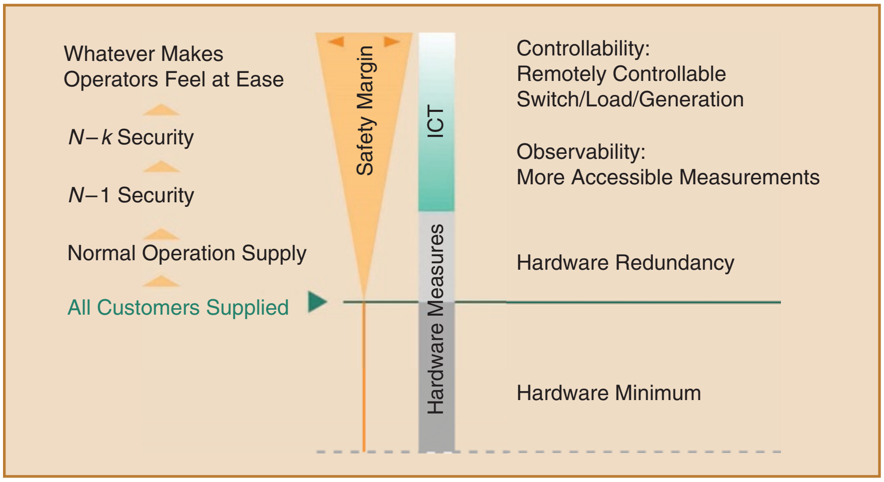

figure 4. The power system resilience layers.

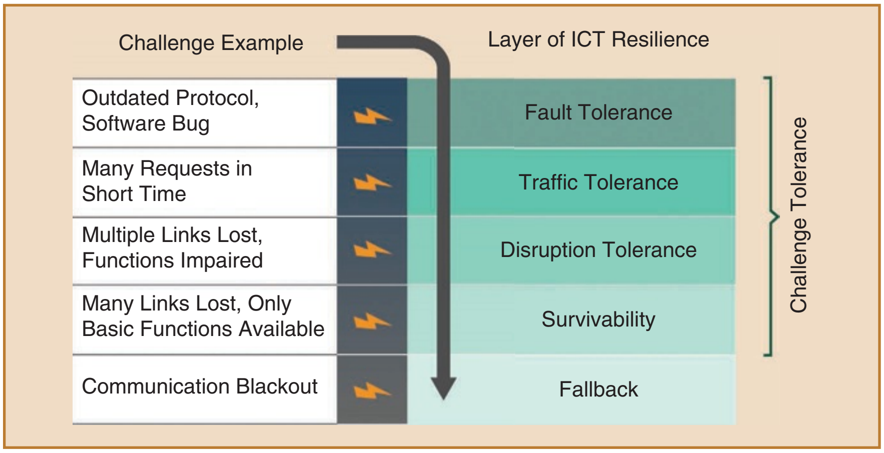

figure 5. The layers of ICT resilience.

Figure 5 depicts a set of properties that describes the resilience of ICT systems. Only if the challenge tolerance (comprising fault tolerance, traffic tolerance, disruption tolerance, and survivability) is at a constantly high level, the power system's resilience can be increased by functions that are ICT dependent. Furthermore, the trustworthiness must be monitored and ensured.

Present power systems are equipped with supervisory control and data acquisition (SCADA) systems on the higher voltage levels. Their design predominantly consists of proprietary physical infrastructure that monitors the availability of power equipment at specific times and provides information used to determine the reliability of the overall network. The access to the SCADA system is strictly limited and thus provides a high level of security. Moreover, the performance in terms of data rate, latency, and other QoSs is designed to meet the operators' needs. Communication lines for power system operation are mainly built without connection to publicly available ICT systems. Full knowledge of the topology and applied mechanisms allows the assessment of the ICT system's fault tolerance regarding software bugs and other randomly distributed flaws. The increasing relevance of distributed SCADA, energy management, and distribution management systems fosters an ICT complexity that endangers the feasibility of fault tolerance assessments. However, the survivability can be assessed for a few random faults, and, in some cases, analysts can evaluate many faults, widespread ones, and even targeted failures. As the latency and bandwidth required for grid operation is one of the design principles, the traffic tolerance is not of great importance for the analysis of SCADA systems in normal operation. However, the available bandwidth could be misused or depleted for a corrupted ICT system. The disruption tolerance indicates the response when links of an ICT system do not work as expected, information is lost, the number of links is reduced, and information is transferred significantly slower than expected.

The resilience of ICT systems can be assessed and designed according to their manageable complexity and degree of seclusion for a limited number of tasks. The trend of digitalization and decentralization fosters the introduction of ICT-dependent functions that use fewer closed and observable ICT infrastructures. This is particularly relevant for lower voltage levels where dedicated communication connections to the large number of components are not feasible. An operator has good reason to trust a remotely controlled switch to act as demanded, and a remotely controlled switch can perform the requested action without intensive plausibility checks for a closed SCADA system. When functions using wide and local area networks via fiber optic, power line, or even wireless communication like WiMAX or 5G start to increasingly appear, it gets much harder to monitor and maintain the resilience of the ICT system and subsequently the cyber-physical power system resilience.

Even if controllable generators, controllable loads, tap changing transformers, and automated switches in the LV grids were connected to a dedicated and sealed ICT infrastructure, the increased complexity of the system creates a need for local intelligence. When the number of links and entry points rises, the number of corrupted signals rises as well and with it the need for local plausibility checks. The more signals a system needs to work properly, the higher the probability of losing signals. This requires strong and reliable plausibility checks as well as a robust fallback configuration of many components, ideally realized in a way that prevents oscillation and cascading.

Cyberphysical Power System Resilience

Power system operational dependence on ICT requires the combined assessment of ICT resilience and power system resilience, called *cyberphysical power system resilience*. Separate assessments of ICT or power system performance are not enough when the interconnected system performance becomes of interest.

There is a discussion about possible threats. In Ukraine, the power system suffered from a coordinated cyberattack in 2015 that led to a widespread blackout. The attackers were able to infiltrate the SCADA system to control switches, disable and destroy communication infrastructure, and slow down restoration by damaging the backup power supplies.

The ICT system that is explicitly used to provide beneficial services for the power system itself could be corrupted, and the general development toward the Internet of Things comes with the risk of increased simultaneity of load events. When electric power systems were designed in the early 20th century, there were no fast coordination mechanisms, so statistical diversity of loads was implicitly guaranteed. However, simultaneity occurs in cases where many customers turn on or off their appliances triggered by an event. An example is the TV pickup phenomenon in the United Kingdom triggered by the final whistle of a soccer match (2.8 GW of additional demand in the United Kingdom alone after the penalties of the 1990 World Cup and 2.6 GW after England versus Brazil in 2002).

More digitalization by the automation of processes at prosumer premises and other generation sites within the distribution system brings flexibility into the system that is necessary with large penetrations of PV and wind energy resources. However, these inverter-based resources can react simultaneously to discrete steps of market prices within seconds. This behavior is already well known for generation scheduling based on hourly spot market prices. After each time block, the ramping-up and ramping-down of generators is visible in frequency time-series measurements and brings significant disturbance to frequency stability.

Today, dedicated cyberattacks can cause high simultaneities in power demand. Furthermore, cyberattacks that do not specifically target the electric power system might still cause massive changes in load, which can affect system performance.

Historically, the reliability and resilience of power systems have depended heavily on hardware oversizing and physical redundancy. With the changing energy landscape and the trend for digitalization and decentralization, there is the opportunity as well as the necessity to augment the traditional reliability approaches with increased awareness, smart control, and local backup strategies. Figure 6

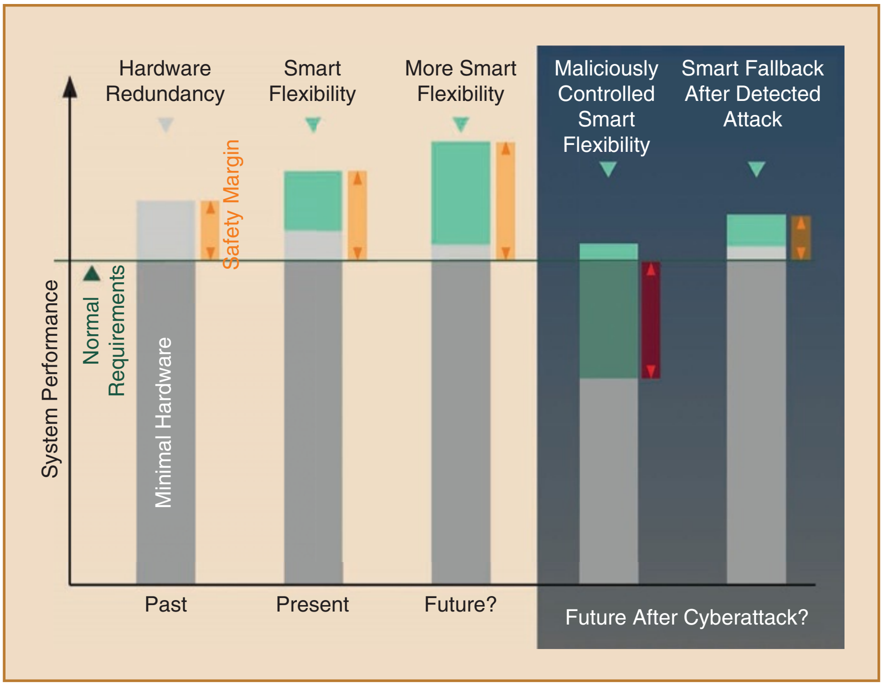

figure 6. The range of possible overall resilience in future power systems. Hardware: gray; smart flexibility: green; safety margins: orange; abused flexibility: red.

> With the changing energy landscape and the trend for digitalization and decentralization, there is the opportunity as well as the necessity to augment the traditional reliability approaches.

schematically represents a range of possible outcomes for the overall resilience of power systems and illustrates how physical hardware redundancy can increasingly be replaced by smart flexibility. However, smart flexibility exposes the system to malicious cyberattacks and malfunctions. Therefore, plausibility checks, validation, and fallback settings decrease the potential damage from loss (or even adversary takeover) of communication and control systems.

Distribution System Islands to Enhance Resilience

In case of a large-scale blackout, i.e., when either the transmission system or the connection to it is unavailable, the formation of distribution system islands can help mitigate the adverse impact. Even if the extent of local generation capacity is limited, there is often the potential to supply at least part of the normal load. If part of the power system can continue operating as an island without interruption, the damage to the customers served can be completely avoided. However, even if customers are disconnected by the initial disturbance, there is significant benefit in reducing the local outage duration.

The increasing penetration of DERs potentially improves the resiliency of distribution islands. However, the distributed nature of many renewable generators presents operational challenges. Furthermore, the stochastic, weather-dependent availability of generation from sources such as solar and wind power increases the number of possible different scenarios a distribution system operator (DSO) may face, which greatly complicates matters.

Here, we present a case study about the possibility of local load coverage while respecting limits for active power exchange with the surrounding power system. Figure 7 displays the amount of load that can be restored in a representative section of a distribution system with a given penetration of DERs for different starting times over a year, depending on the required duration. The study considers nameplate values of 133 MW for PV plants, 108 MW for wind farms, and 12 MW for biomass plants; the average load for normal operation is 22.4 MW. The analysis accounts for the availability of remote controllable switches and the actual feeder configuration, as well as time series data for load and generation of the year 2014, with the renewable generation scaled up according to a midterm future scenario.

In Figure 7, the *y*-axis shows the amount of load that can be covered under the given constraints. The *x*-axis represents starting times during the year, sorted by coverable load. The individual lines represent different constraints concerning the required minimum duration of supply. The (small) area below the line "18 h" represents what can be done (and how often) if only the connection of feeders is

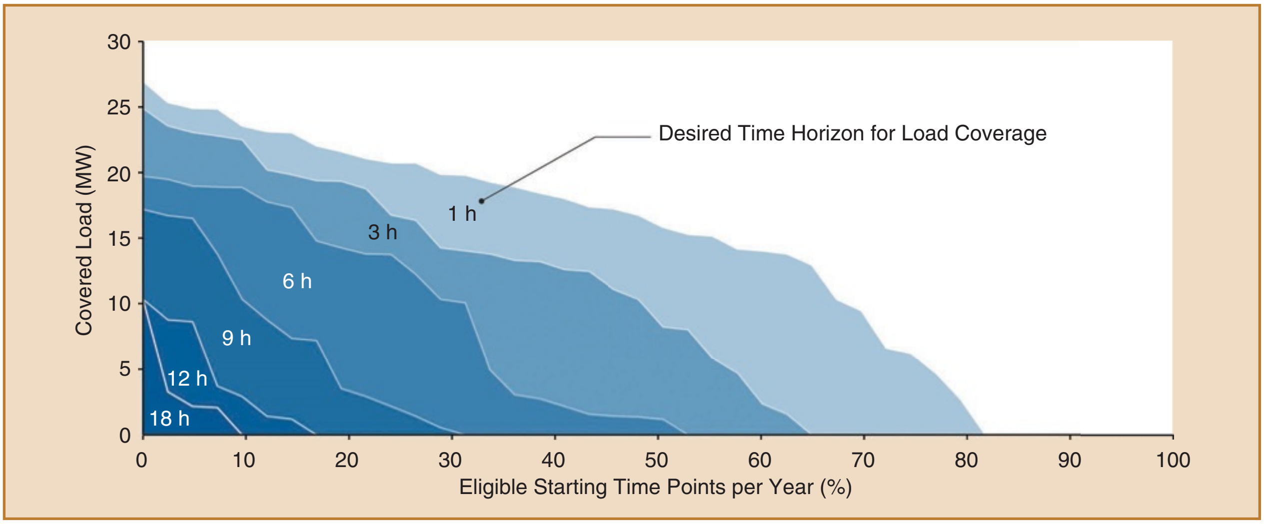

figure 7. The suppliable load over the year.

allowed that can be covered for at least 18 h. The area under the line "1 h," on the other hand, represents the potential for supply if that constraint is relaxed to just 1 h of uninterrupted supply. At most times, a certain measure of supply is possible but the requirement of sustained supply over many hours significantly reduces this option: supplying 15 MW over 3 h is possible approximately 40% of the time over a year. However, if the requirement is continuous supply over 9 h, this is only during less than 10% of the year. This highlights the regulatory challenge of providing clear criteria on temporary resupply: Is it better to intermittently supply a feeder for a single hour or to leave it disconnected until permanent resupply is possible?

All the load cannot be covered all the time. Topological restrictions and the assumptions of limited controllability (balancing of load and generation) is assumed to be only possible by HV-connected units, such as 39-MW PV plants and 72-MW wind parks. The remaining generation is connected at the LV or MV level and not considered to be reliably controllable in a restoration situation. Even though the biomass plants are assumed to be available 24/7 with 80% of their nominal power, they could not be utilized at all times because they are connected to the lower levels of the distribution system and can neither be remote-controlled in a blackout-safe manner nor can be topologically separated from the local load. Extending plant controllability and topological flexibility to the lower voltage levels can improve the capabilities of load coverage significantly.

Battery storage systems might allow more load to be connected more often (more eligible starting time points for a given level of supply), but unless they provide dedicated reserves for power system restoration (which seems unlikely, given the current economic incentives), there will still be remaining unavailability because of empty storage capacity. Storage systems that normally optimize their depth of discharge for long lifetimes might be able to provide additional reserves during emergencies. However, there is currently no regulation that could incentivise such operation modes of storage systems.

Since blackouts might be the result of a natural disaster (e.g., extreme weather conditions), power outages can coincide with the loss of some communication infrastructure. A restoration-friendly fallback behavior of DERs potentially contributes to fast and reliable restoration of as much load as possible. For further information, see "The Importance of Active Power Control in Restoration."

The Impact of Different Islanding Strategies on Resilience

A very common strategy of DSOs to deal with outages of the transmission system is to wait for the transmission system to become available again. This is very simple and, at least historically, justified because DSOs did not have generation capacity within their power systems. This case "without islanding" serves as a reference to assess the potential benefits of distribution system islanding.

Operating a distribution system island is an option if at least some generation of enough size is available within the distribution system. This generation must either have the capability for black start or have entered house load operation at the time of the blackout. Such generation is

The Importance of Active Power Control in Restoration

Balancing the demand and supply of active power can be especially challenging in small islanded distribution systems. The overall inertia of rotating machines in the system is typically limited. Furthermore, the effect of cold load pickup makes the initial load upon reconnection of feeders highly uncertain.

Since distribution system operators often do not have the equipment to switch individual customers at the lower voltage levels, the minimal amount of load that can be connected in a single step is often in the order of magnitude of several megawatts. Therefore, frequency control contributions from distributed energy resources become highly desirable.

Operating generators below their available primary energy provides additional active power in the event of frequency drops, which counters imbalances between supply and demand. This can be achieved either by providing a reduced active-power set point via remote control or by prescribing a corresponding behavior when reconnecting after an outage. The latter can serve as the standard behavior for generators without a communication connection and as a fallback setting in case communication systems become unavailable. The strategy also significantly increases the allowable load increment for a given power frequency nadir. Therefore, it is possible to connect larger feeders or more feeders at a time with a given level of confidence in stable operation.

Furthermore, a larger capacity to absorb power imbalances can also increase the chance of intended islanding. If successful, transition to an islanded subsystem can turn a potential blackout into a system split. However, this requires predefined separation points and is currently only possible for comparatively small parts of the power system with a single (or few) connection point(s) to the rest of the system (microgrid). Moreover, the condition of unintended islanding must be avoided for safety reasons.

typically a HV- or MV-connected gas or hydro power plant or might, in the future, be a renewable energy plant with grid-forming capability.

To achieve restoration, the DSO can select some feeders, ideally with rather predictable load, and successively connect them to the islanded system. Leaving sufficient reserves for stable operation of the islanded system is a high priority. This case is designated as "with islanding" in Figure 8.

Often, and increasingly, distribution systems also include several smaller DERs such as wind, PV, and biogas generators. If such generators are available and the DSO has at least approximate knowledge of their location and expected active power in feed, they can increase the overall available active power and thus allow for supply of more load. This is shown in Figure 8 as the "islanding with 25% DGs" case.

If the DGs are also known to contribute to active power frequency control, they increase the final amount of load that can be supplied and also the allowable load increment that can be connected in a single switch action. In this way, DGs with frequency control can form an island considerably faster than would otherwise be possible. In Figure 8, this case is labeled "islanding with DGs contributing to frequency control."

Figure 8 shows the supplied loads, the loss of supply, and the total amount of lost energy, respectively, for a hypothetical example of a blackout from 6:00 a.m. to 12:00 p.m. The total amount of energy not delivered to customers can serve as an indicator of the overall damage caused by an outage. Although damage can be reduced by islanded operation, the exact tradeoff of justified investment is far from obvious. It should be noted that a contribution by DGs to frequency control does not only make restoration faster but also more reliable.

Defining a universal cost function that weighs the costs of a prolonged outage against potential repeated outages does not seem feasible. How to assess uncertainty regarding available generation and load demand is not only an issue of the power system but depends on regulatory requirements and incentives to the relevant actors. However, many requirements are dependent on scenario assumptions and have not been mathematically formulated by regulators. A valid, pragmatic approach maximizes the expected value of covered load, i.e., the integral of supplied active power, over the considered time period. Figure 3 illustrates a schematic of a possible enhanced cost function, including nonlinearities.

Socioeconomic Tradeoff

Resilience is an open-ended optimization goal in the sense that it can never be completely achieved. Therefore, the diminishing returns of ever-increasing investment in a more resilient power system are certain to be outweighed by the cost of the increasing mitigation effort at some point.

Mitigation includes the following measures:

- ✔ islanding capacities
- ✔ classic physical redundancy
- ✔ fallback settings
- ✔ ICT for better observability of the system
- ✔ smarter inverters
- ✔ stability increasing ancillary services
- ✔ robust planning
- ✔ traded flexibilities
- ✔ load prioritization.

Expenditures occur in terms of monetary cost, land use, social impact, and so on. Likewise, expected damage encompasses loss of welfare in general terms (including social and

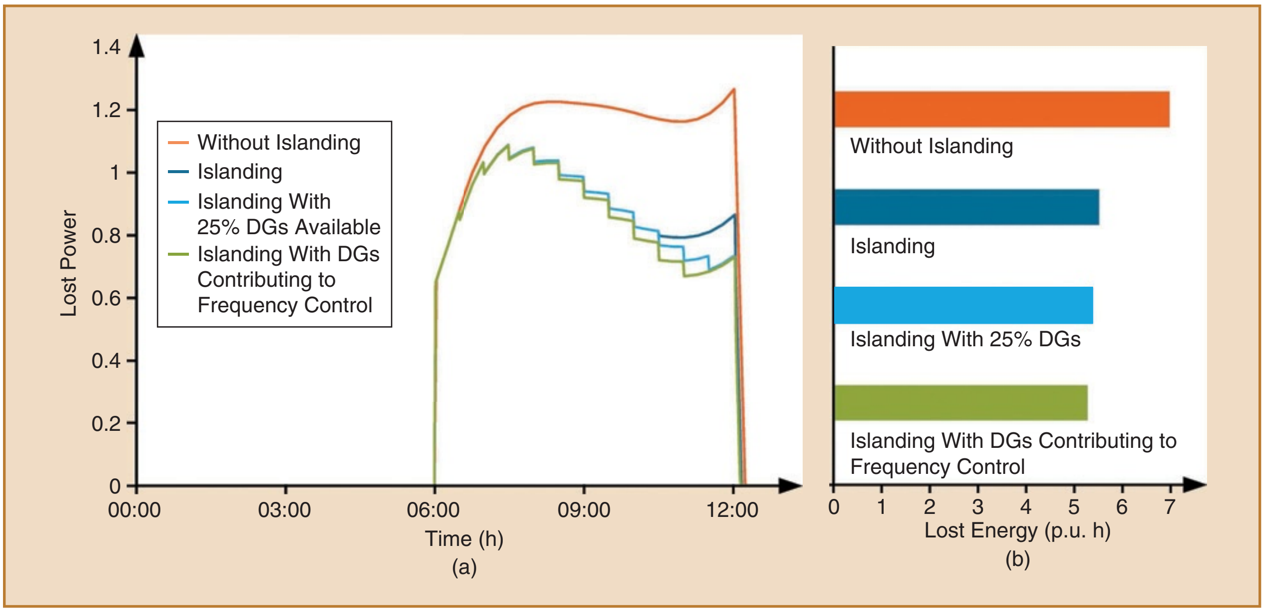

figure 8. The (a) lost power and (b) lost energy for different islanding scenarios. p.u.: per unit.

Regulatory Incentives Concerning Blackouts

In Finland, utilities must compensate their customers for outages that last longer than 12 h. The compensation depends on the duration of the outage and can be up to 200% of the yearly electricity bill.

In Germany, there is no direct compensation of residential customers. Instead, there is regulation that incentivizes utilities to minimize the System Average Interruption Duration Index. However, the calculation excludes acts of nature beyond control/force majeure.

Likewise, utilities in the United States extensively exclude causes beyond control, maintenance, and even their own operative actions from their service guarantee programs that regulate customer reimbursement in case of outages. Beyond the direct financial incentives, there are also regulatory obligations for utilities since power systems are considered critical infrastructure.

economic cost and danger to human life, among others). Therefore, the definition of the accompanying cost functions goes beyond the domains of engineering and economics and must also entail political decision making (see "Regulatory Incentives Concerning Blackouts").

Currently, the way of dealing with these tradeoffs varies greatly among different power system operators, regulators, and political decision makers. The choices are often made based on a mixture of history and intuition. More sophisticated approaches are needed to achieve an optimal or at least near-optimal solution.

Summary

Increasing the resilience of the power system is one of the major objectives for grid operators. This article provides perspectives regarding different tradeoffs used for evaluating and improving power system resilience.

The evolution toward an ICT-dependent power system provides increased operational flexibility and cost-efficiency, but a more complex cyberphysical power system also poses risks to resilience. As another perspective, the decentralization of power supplies combined with digitalization allows the implementation of microgrids in distribution systems. Potential benefits of intended islanded operation during blackout situations increases power system resilience but presents implementation challenges.

The opportunities and challenges discussed in this article are still reflected poorly in the regulatory framework. Significant effort is required to fully understand, quantify, incentivise, and implement adequate measures that can be used to make the future power system even more reliable and resilient at acceptable cost.

Acknowledgments

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Nipping Blackouts in the Bud

Introducing a Novel Cascading Failure Network

By Hyde M. Merrill, Md Abid Hossain, and Marc Bodson

CASCADING BLACKOUTS ARE THE OLDEST MAJOR unsolved technical problem in power system engineering, highly visible since the Northeast Blackout of 1965 in North America. In this article, we review some cascading blackouts and past work on the problem. New metrics measure network stress to identify and reduce the risk of cascading failures.

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Excellent models of large power systems are used worldwide to simulate the hardware that generates and transmits current. However, the systems also include control and protection equipment as well as practices and procedures. We argue that these critical ancillaries are too complex to be observed or modeled at a large scale. They must be designed and operated with care, but we cannot expect perfection.

In the cascading problem, one failure leads to a chain of others in an essentially undamaged bulk power system,

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Cascading blackouts are the oldest major unsolved technical problem in power system engineering, highly visible since the Northeast Blackout of 1965 in North America.

ending with generators and customers being disconnected. Before cascading starts, three factors are always present: failures happen in the ancillary elements mentioned previously, the system is fully operational though under stress, and the system is large. We do not treat the important, but different, problem of blackouts caused by widespread physical damage from external causes.

Our new metrics come from network and power system theory. They quantify stress, or the susceptibility of a system to cascading failures. The metrics use a new network, based on known engineering principles, to show how failures propagate through a system. In contrast, ordinary models measure how power flows through a system.

We describe research conducted by the University of Utah and the Western Electricity Coordinating Council (WECC). The use of real data on full-scale systems, including data on a preblackout state, is an unusual and valuable feature of our studies. The stress metrics were calculated for a very large system [the Western Interconnection (WI) of North America] and a large section of this system [Southwestern WI (SW WI)] in a wide range of conditions. Even for a very large system, the computations are easily performed. The metrics agree with informal stress judgments by experienced utility engineers. For the SW WI just before a major blackout, the stress measured by the metrics was very high. The metrics flagged areas and facilities involved in the cascading as being particularly vulnerable or critical in the preblackout state. The computation of these metrics in real time and in power system planning is a promising tool for forestalling future cascading blackouts.

The Importance of Cascading Blackouts

A cascading blackout is an uncontrolled, unexpected chain of cause-and-effect failures in hardware used for generating and carrying current. The event interrupts bulk power service over a large area. Cascading blackouts matter because it can take days to restore the system. Meanwhile, many functions of society are disrupted, with losses sometimes reaching billions of dollars.

Typical Cascading Blackouts

On 9 November 1965, a famous cascading blackout occurred with relatively heavy flows on five essentially parallel 230-kV lines between Niagara Falls and Toronto, Canada. Unbeknownst to the operators, backup relays set for other purposes would disconnect or trip the lines well below their capabilities. A relay tripped one line. Power flows on the other lines increased instantly to compensate. They tripped too, separating New York from most of Ontario. The demand and generation in each of the two separated systems were suddenly out of balance. The systems could not absorb their imbalances and blacked out.

On 14 August 2003, precursor events in Ohio and nearby areas of the Eastern Interconnection of North America included procedural failures in two control centers and computer failures as well as generation and transmission mishaps. Three 345-kV lines failed between 15:05 and 15:46 Eastern Daylight Time, the first at only 44% of its rating. Although not overloaded, they were loaded more than usual due to earlier events. One by one, the lines heated and sagged into trees that were taller than they should have been, due to poor vegetation management by the owner. Each contact took a line out of service, increasing the heating and sagging of the other lines.

A relay interpreted high current and low voltage as a short circuit at 16:06 and tripped a fourth 345-kV line. The system could not survive this and changed from "slow cascading" to "fast cascading," creating electric islands with unsustainable demand-supply imbalances and leaving millions without power. This blackout cost the United States between US$4 billion and US$10 billion. Manufacturing shipments in Ontario were down CAD$2.3 billion that month.

On 28 September 2003, at 3:00 a.m. Sunday (an hour, day, and month of low demand), Italy was importing 6,400 MW, 300 MW more than what was contracted from France, mostly via Switzerland, in part to fill its pumped-hydro plants. A heavily loaded 380-kV Swiss line got hot, sagged into a tree, flashed, and stayed open. Swiss dispatchers asked Italian dispatchers to reduce their imports by 300 MW to comply with the schedule. This solution did not work, as the schedule was premised on all lines being in service. The Swiss could have asked the Italians to stop pumping their hydro storage plants but did not. A second line sagged on to a tree and tripped at 3:25 a.m. Within seconds, all lines into Italy tripped, isolating Italy with less online supply than demand. In 3 min, all of mainland Italy blacked out. The rest of Europe had more supply than demand, but this much larger system recovered from an imbalance that was too much for Italy. The official Union for the Coordination of Transmission of Electricity report on the event noted that the system was N–1 compliant before the first outage because corrective actions were available and there was time to take them should the outage occur.

Instructive Blackouts That Did Not Cascade

On 11 April 1965, 37 Palm Sunday tornadoes in Ohio, Michigan, and Indiana took 27 American Electric Power Company transmission lines and two extra high voltage (EHV) substations out of service. Customers on failed radial lines lost power, but no cascading was reported. The event occurred on a Sunday in a low-demand month. The system was not designed to survive 29 contingencies; however, it was lightly loaded and not stressed by any definition.

In January 1998, during a Quebec–New York ice storm lasting several days, many overhead transmission and distribution lines in a large area were on the ground. The affected region was blacked out, but cascading was not a factor. The extent of the damage remained confined, credited to adequate automatic and manual responses.

Nonetheless, Hydro-Quebec may be classified as a smaller system, and the loosely coupled Upstate New York area involved was unquestionably small. In general, smaller systems do not seem to be vulnerable to cascading blackouts. A representative of the Electric Reliability Council of Texas (ERCOT) system told one of us that operation had been sustained in extremis several times, sometimes with controlled rolling blackouts, but without cascading. ERCOT is connected only loosely to the two huge abutting Eastern Interconnection and WI of North America.

Large-Scale Blackouts Due to Massive Destruction

Puerto Rico was blacked out by Hurricanes Irma and Maria, which destroyed much of the island's electrical infrastructure in September 2017. Two other large-scale destruction events were described in the previous section. Significant work is being performed on this problem as discussed elsewhere in this issue of *IEEE Power & Energy Magazine*, in part exploring the notion of resilience. Such blackouts are caused by massive external events, unlike the cascading failures referenced in this article. Major catastrophes cause extensive physical damage, especially to the distribution system; any cascading is of secondary importance. The damage can take weeks or years to repair. Cascading blackouts, in contrast, are due to internal failures of a functioning system. They mostly involve EHV/HV transmission, with little, if any, physical damage. The system is usually restarted within hours or days. The two problems have different causes, effects, and solutions.

What Have We Accomplished Since 1965?

NERC and the N–1 Criterion

After the 1965 blackout, the U.S.-Canadian power industry created the National Electric Reliability Council (NERC) (now the North American Electric Reliability Corporation) to improve reliability. NERC developed planning and operating criteria based on principles developed previously by North American utilities, which did not fully consider cascading. The details of these criteria have evolved while remaining consistent in their basic concepts. With limited exceptions, NERC standards mostly assume that ancillary control and protective devices, and practices and procedures, work properly.

One key concept is that a system of "*N*" elements should be designed and operated to withstand, without major interruption of service, the unexpected loss (outage or contingency) of any single element. This notion leads to the "*N*–1 criterion," simple in principle but nontrivial to apply. The elements modeled as at risk by the NERC criteria are mainly transmission hardware, with less emphasis on generation.

Early Observations on Cascading

Vannevar Bush was a brilliant electrical engineer and chair of the U.S. Office of Scientific Research and Development during World War II. In a 1970 book, he blamed cascading blackouts on the enormous growth of power systems and their interconnection over vast regions. He predicted that there would be more blackouts based on engineering common sense: the more complex something is, the more likely it is to fail. Nonetheless, a common prescription over most of 50 years has been that to prevent cascading blackouts, power companies just need to adhere better to the NERC criteria, maybe with some fine-tuning. There has been little recognition that solving the problem would require new thinking.

Hidden Failures

A NERC study found that 73.5% of significant cascading events were caused or aggravated by unobservable "hidden failures" of the protection system, including relays, breakers, and so on. Many researchers have responded with interesting work. For example, Chen et al. created a probabilistic failure model, recognizing that heavily loaded systems are more prone to blackouts. They assumed that the probability of a line tripping incorrectly is low when the line is loaded below its rating. If the flow increases from 100 to 140% of line rating, their assumed probability of incorrect trips increases linearly to one. They concluded that increased spinning reserve, a more robust protection system, and faster control actions will reduce the risk of cascading.

The notion of hidden failures is so apt that we have wrested it from the protection system context and applied it to any unobservable element of the power system. These elements include the various triggering failures in the cascading blackouts described previously. Every blackout seems to involve different hidden failures. Each failure seems simple, but to instrument the system to detect them all is fundamentally impractical. The system is too complex, and there are too many ways it can fail.

Multiple Contingency Studies

Long-standing, incorrect assumptions can hinder the understanding of cascading blackouts. For instance, several studies on cascading have assumed that power systems are generally operated to be N–1 secure; therefore, most cascading has been triggered by multiple independent outages. Thus it is thought necessary to consider daunting numbers of simultaneous combinations of two outages.

In fact, multiple independent NERC-criterion outages have directly caused few, if any, cascading blackouts. In the 8 September 2011 blackout (described later in this article), the system was clearly not N–1 compliant. The systems were N–1 compliant before both 2003 blackouts, and the operators apparently thought their system was compliant in 1965. But in each of these three events, a single outage, abetted or triggered by failures in ancillary elements, triggered one or more secondary outages and cascaded to the blackouts.

A multiorganization committee chaired by N. Bhatt studied multiple contingency chains (two simultaneous independent outages causing overloads and further outages). Their summer peak model of the Eastern Interconnection of North America consisted of approximately 50,000 buses and 65,000 branches. A list of roughly 250 single contingencies was considered. More than 31,000 double-contingency pairs were created from this list and simulated. Only 953 of these double-contingency events led to overloads. For most of the 953 overloads, there were no further overloads once the overloaded branches were tripped. Only 38 of the 953 led to cascading. This approach, its statistical analysis, and its conclusions parallel and differ from ours in important ways.

The NERC Criteria May Not Be Sufficient to Prevent Cascading Events

After nearly 40 years of cascading failures, p. 23 of the postmortem report, produced ad hoc under the direction of the U.S. Secretary of Energy and the Minister of Natural Resources Canada, on the 14 August 2003 U.S./Canada blackout reached a momentous conclusion. At 15:05, before the slow cascading of the four 345-kV lines that ended in fast cascading, "FirstEnergy's … system [at the heart of the cascading] was electrically secure and was able to withstand the occurrence of any one of more than 800 contingencies … [T]he system was electrically … in compliance with NERC's operating policies. [But] there was clear evidence that the … area was highly vulnerable …" In fact, the system did not withstand the 15:05 contingency (at 44% of the line's rating) but cascaded slowly, as line by line the increased loading, line temperatures, and sagging into trees proceeded.

There is an important fine point here. In 2003, Ohio's FirstEnergy was in compliance with NERC's criteria but was still vulnerable. How can this be? The postmortem report explains: satisfying the criteria means that "while it was possible to operate the system securely," there was no guarantee that this would happen. In particular, failures in control and protection devices, or in practices and procedures, can cause cascading whether the system is NERC compliant or not (see Table 1). The 2003 Italian blackout described previously is a supporting example. In both blackouts, there were sufficient such failures.

System Model and Necessary Conditions for Cascading

Our recounting of cascading events suggests a new conceptual model of the bulk power system, which includes three intertwined elements: current producing and transmitting equipment, control and protection devices, and practices and procedures. These elements, like Borromean rings (Figure 1), form an inseparable system. But if any of the three rings breaks and is removed, the other two fall apart. This also holds for the power system. Most of the emphasis has been placed on studying current-producing and transmitting equipment. Nonetheless, history shows that failures in the two ancillary elements and system stress are necessary contributors to cascading blackouts. The three elements interact

table 1. The three conditions needed for cascading blackouts to occur.

1	Failure in Control and protection equipment or Practices and procedures
2	When the system is stressed
3	The system is large

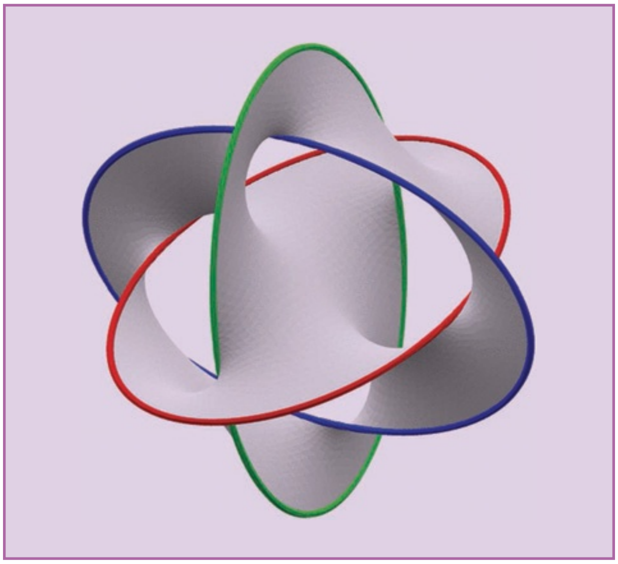

figure 1. Borromean rings with soap film. (Source: Ken Brakke, Susquehanna University; used with permission.)

in both obvious and complicated ways, symbolized by the white soap film on the rings in Figure 1.

Borromean rings are either whole or broken, but we do not know how to measure how stressed the generation and transmission equipment is. Further, there is no way to know if everything in the two ancillary elements (the control and protection devices as well as the practices and procedures) is working properly, as they are largely unobservable. But the power system has built-in redundancies. Unlike the Borromean rings, the power system usually holds together when none of its three elements functions perfectly, yet all three are necessary to its operation. So, to conclude this illuminating, but imperfect, analogy, it is hard to know when the power system is relatively secure or at immediate risk of a cascading failure.

Based on past events, Table 1 lists three conditions that seem necessary for a cascading blackout to occur. Every cascading blackout we know of met all three conditions. More robust systems withstand greater stress or more extreme failures.

A Cascading Outage Network

Network Theory

Graph (network) theory arguably began with Euler's 1736 proof that it was impossible to stroll across all seven bridges in the city of Konigsberg without crossing any of them twice. Most of network theory's development occurred in the last century. Figure 2 displays a generic model of a network. Networks are composed of vertices (nodes) and edges connecting the nodes. For our purposes, network theory is motivated by the three following observations:

1) Large networks are common.
2) Large networks are too big to study element by element.
3) "Big is different." Large networks behave differently than small networks.

What constitutes a large network is not defined in the literature, as systems grow in different ways. In *Six Degrees*, Duncan J. Watts observed that the problem with systems like the power grid is that they are built of many components whose individual behavior is well understood but whose collective behavior can sometimes be orderly and sometimes chaotic, confusing, and even destructive. For large networks, one must therefore study their structural properties and metrics.

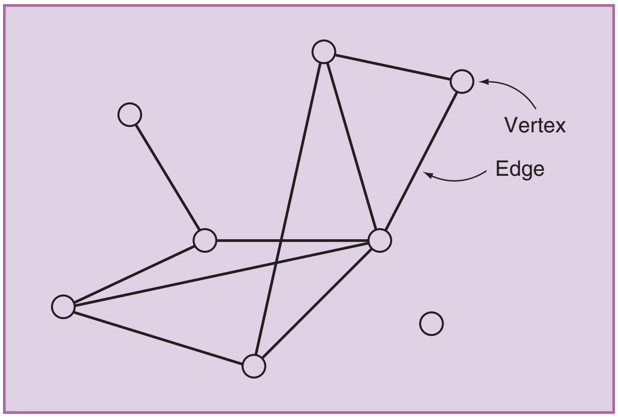

figure 2. Network nomenclature. (Inspired by M.E.J. Newman.)

Power-Flow Network

On a daily basis, power system operators and transmission planners use power-flow software of various kinds. These programs simulate how power produced by generators flows through the network to the customers, in accordance with the laws of electric circuits. In these simulations, the generators and customers are connected to the network at its vertices, called *buses*. The edges are power-transmitting branches, mainly lines and transformers. The math that drives this software operates on a large matrix of numbers, called ***Ybus*** (bold type denotes matrices). **Ybus** represents the electrical properties of each branch and identifies the nodes to which each branch is connected.

Cascading Failure Network

The study of cascading outages needs a different network model because the objective is to study how branch failures propagate throughout the system, rather than how power flows through the various branches. It turns out that the failure of essentially any nonradial branch is linked to essentially every other such branch, not by individual lines but by the network as a whole. In the cascading blackout network, the vertices are branches (lines, transformers, and interfaces), and the edges are line-outage distribution factors (LODFs) [or, more pronounceably, distribution factors (DFAXes)]. This is radically different from the vertices and nodes of the power-flow network. But like the power-flow models, the cascading failure model is built around a large matrix, this one consisting of all the DFAXes. Each DFAX specifies how much the outage of a particular branch changes the flow in another (monitored) branch, with the generation and demand at the various buses not changing. The higher the postoutage flow on a monitored branch, the greater the risk of cascading.

The cascading failure network calculations operate on a matrix consisting of all the DFAXes. This is similar in concept to the power-flow software operating on **Ybus**, although the math is very different.

DFAXes usually have values between −1 and +1. A DFAX of zero value means that the outage of a particular branch will not change the flow on the monitored branch. A value of 0.5 (or −0.5) means that half of the flow carried by the outaged branch will be added to (or subtracted from) the monitored branch's precontingency flow. The **DFAX** matrix is much larger than the **Ybus** matrix and fundamentally different.

Commercial power-flow programs compute the DFAXes from **Ybus** using conventional circuit analysis. DFAXes are well known and often used in planning studies. What is new here is using them to define a failure network and derive metrics for network stress. These metrics, in turn, are used to assess the risk of a cascading blackout. Most nonradial branches are both monitored and outaged. The computations are practical even for the largest systems.

Vulnerability Metrics

The vulnerability of a branch is a measure of how its flow is affected by outages of the other branches in the system. This measure of stress is reasonable, as cascading always begins with one outage causing other branches to become highly loaded and fail. Two vulnerability metrics have been defined: vulnerability rank (RankV) and vulnerability degree (DegreeV).

For illustration, the postoutage flows for a small network were computed from DFAXes and preoutage flows. We skip the computations as they are not new or interesting, but the results are (see Table 2).

Two branches are outaged, one at a time. The right-most column in the gold field states that after an outage of branch 3, the three monitored branches will carry 115, 443, and 0 MW, respectively. The column just to the left in the gold field shows what happens after the outage of branch 1: the three monitored branches will carry 0, 481, and 125 MW. Most branches are both monitored and outaged, but there may be exceptions. In Table 2, branch 2 is monitored but not outaged.

Are the postoutage flows in Table 2 a problem? That depends on how they compare to each monitored branch's rating, given in the first column of the table. (Parenthetically, line ratings depend on such parameters as the thickness of the conductors and their height above ground or obstacles. Transformer ratings are provided by the manufacturer but can be increased by improving the transformer cooling or by limiting the hours they are heavily loaded, as transformers can get hot enough to be damaged when they are heavily loaded for long periods.)

For instance, in Table 2, the outage of branch 1 will cause 125 MW to flow in branch 3. This is greater than branch 3's 102-MW rating. Expressed differently, the postoutage flow will be 125/102 = 1.23 times branch 3's rating.

The postoutage flows in megawatts (the gold field in Table 2) are converted to fractions of the branch ratings in the gold field of Tables 3 and 4. (See the 1.23 calculated above in the lower left of the gold field in each table.) The rest of the gold fields of Tables 3 and 4 is calculated from the gold field of Table 2 exactly the same way.

The simple gold fields in Tables 3 and 4 are the heart and soul of this article. For each of the branches we monitor through calculations, the gold field in Table 3 tells how it will be loaded after every outage, one outage at a time. And Table 4 tells how seriously each possible outage will affect the monitored branches.

The gold field can be huge for a real system. We found two simple but powerful apps to mine very useful information from all of this data on how stressed the branches and the network are as a whole. Tables 3 and 4 illustrate these two apps. They can be defined mathematically, but Tables 3 and 4 summarize the branch calculations. Later in this article, we show how to extract the metrics of system stress from the branch metrics.

Our first stress metrics measure vulnerability—how much a particular branch is at risk of overloading and

table 2. Postoutage flows and ratings.

Monitored Branches		Outaged Branches	
Ratings (MW)	**Branches**	**1**	**3**
235	1	0	115
512	2	481	443
102	3	125	0
		Postoutage flows (MW)	

table 3. Postoutage flows and vulnerability metrics.

Vulnerability (Monitored Branches)			Outaged Branches	
RankV	**DegreeV**	**Branches**	**1**	**3**
0.49	0	1	0	0.49
0.94	2	2	0.94	0.87
1.23	1	3	1.23	0
			Postoutage flows (fractions of monitored branch ratings)	

RankV = the maximum postoutage flow in each row.
DegreeV = the number of postoutage flows greater than the threshold in each row.
Threshold = 0.75 or 75% of the monitored branch ratings.

table 4. Postoutage flows and criticality metrics.

	Criticality (Outaged Branches)		
	RankC	1.23	0.87
	DegreeC	2	1
Monitored branches	Branches	1	3
	1	0	0.49
	2	0.94	0.87
	3	1.23	0
		Postoutage flows (fractions of monitored branch ratings)	

RankC = the maximum postoutage flow in each column.
DegreeC = the number of postoutage flows greater than the threshold in each column.
Threshold = 0.75 or 75% of the monitored branch ratings.

> Unlike the Borromean rings, the power system usually holds together when none of its three elements functions perfectly, yet all three are necessary to its operation.

cascading due to an outage. One measure of vulnerability, RankV, is the highest postoutage flow on the branch, considering all possible outages, one at a time. This can be picked right out of the gold field. The highest number in the bottom row of the gold field, 1.23, is the maximum postoutage flow (RankV) of branch 3, considering all (both) outages. For the next row up, the highest number is 0.94, the RankV of branch 2. And from the top gold row, the RankV of branch 1 is 0.49. Each of these numbers, 0.49, 0.94, and 1.23, is listed in the leftmost column of Table 3. These are the maximum postoutage flows on each monitored branch in terms of the branch's rating, a measure of its stress. So, our first app finds the maximum loading in each row.

Another measure of vulnerability, DegreeV, is the number of outages that will load each branch above some worrisome threshold. We will use 0.75 as the threshold here. The DegreeV can be found easily from the gold field of Table 3 using a simple counting app. Just one outage will load branch 3 over the threshold, so the DegreeV is one for branch 3. Similarly, the DegreeV is two for branch 2 and zero for branch 1. The DegreeV metric values for the three monitored lines are in the second column in the tan field.

Why would it be reasonable to use a threshold other than 1? In the 1965 and 2003 U.S./Canada cascading blackouts described previously, the cascading began below the official ratings of the lines due to hidden failures. As discussed later in this article, the precise value of the threshold is not critical.

We have presented two apps, maximizing and counting, to define the reasonable vulnerability stress metrics that measure the risk of particular branches overloading. We will next use these two apps to define the metrics that measure how critical particular outages are, which is quite a different question.

Criticality Metrics

In the rightmost column of the gold field in Table 4, 0.87 is the maximum load on any of the three monitored branches after the outage of branch 3. So the criticality rank (RankC), of the outage of branch 3 is 0.87. In the left gold column, the maximum load (RankC) on any monitored branch after the outage of branch 1 is 1.23. These two RankC values are recorded in the blue area of Table 4 in the RankC row.

We next use the counting app to compute the degree of criticality (DegreeC) of the outages. After the outage of branch 3, one monitored branch will be loaded above 0.75. After the outage of branch 1, two monitored branches will be loaded over 0.75. These two DegreeC values, one and two, are recorded in the bottom row (DegreeC) of the blue area of Table 4.

In summary, two simple apps, maximizing and counting, are applied to the rows and columns of the gold field of Table 3. The resulting metrics measure the vulnerability of the monitored lines to cascading and the criticality of the various outages. A mnemonic may be helpful: a vulnerable branch is a victim, and a critical branch is a culprit. Vulnerability metrics are computed by rows of the gold-field matrix of postoutage flows and the criticality metrics by columns. The four rank and degree metrics are complementary measures of the cascading risk of a network in terms of individual branches and outages. The evaluation of the metrics across the network gives a multidimensional measurement of the overall cascading risk.

We have gone to great lengths to show how Tables 3 and 4 were developed. Having computed the stress metrics, planners and operators may make special efforts to protect the most vulnerable and critical branches. Possible actions include verifying the branch ratings, scheduling maintenance activities for off-peak periods, and reducing the flows on these branches. We will return to this topic in discussing our WI study.

Former Studies and Disclaimer

The analyses of stress for networks in the eastern United States and Peru were presented previously (see Merrill and Feltes in the "For Further Reading" section). Here we discuss in-depth analyses of the WI of North America, roughly the contiguous United States and Canada west of the Rocky Mountains (omitting the northern-most portions) and part of northern Mexico. Preliminary results were presented previously and can be found in Hossain et al. in the "For Further Reading" section.

Although we discuss weaknesses of the network in certain conditions, we are not critical of the operation of the WI. The problems described are typical in the industry. Also, the WI system evolves constantly as facilities are added and upgraded. The results we present do not necessarily reflect the state of the system at any other time or for other conditions.

Western Interconnection Study

The WI study conducted by the WECC and the University of Utah used high-quality power-flow base cases, which are listed in Table 5. The 2012 and 2016 cases were built by WI utilities and the WECC for operating studies and are not snapshots of moments in time. They are highly realistic and consistent because they were prepared by the same engineers for the same purposes using consistent assumptions. Of course, the dispatch of generation reported in Table 5 for the high-demand cases was different from dispatch reported for low-demand cases. As the high demands in winter, spring, and summer also differed from each other, so too did their dispatches, and the same was true for low-demand winter and summer cases. There was one theme: the SW WI was almost always a net importer from remote power plants, and the demand in every case was greater than the local generation. Being able to compare consistent, though different, load and generation patterns was very useful.

It is rare for such data to be available, and it is unheard of to give researchers access to a preblackout reconstruction, such as the 2011 preblackout information listed in Table 5. The WI study was unique in that it used realistic data on a full-scale system, and the enhancing contribution of the WECC to the study of cascading blackout prevention is gratefully acknowledged. The 2012 and 2016 cases were not intended to be $N-1$ compliant; they were meant to be used in operating studies to identify and resolve problems. Unfortunately, the 2011 preblackout case was not $N-1$ compliant due to failures in practices and procedures. All of this data was provided by the WECC and handled, purged, and reported on under a strict Critical Energy/Electric Infrastructure Information discipline.

LODFs

Most of the analyses discussed in this section considered only monitored and outaged branches in the SW WI, but the DFAXes incorporated the branches and flows in the entire WI. Figure 3 shows the distribution of the values of DFAXes for outaged and monitored branches in the SW WI, which is typical of such distributions for other systems. For example, the 2016 summer high-demand case (the upper curve) had roughly 5.79 million DFAXes. Figure 3 shows that most of them are very small, with only approximately 43,500 having absolute values greater than 0.1. The absolute values of just 4,305 DFAXes were greater than or equal to a large, but arbitrary, 0.7. (The 0.7 in this figure has no special significance and is unrelated to any other 0.7 in this article.)

Figure 3 has two very significant properties. First, 4,305, a large number, if that many outaged/monitored branch pairs are at risk of cascading, is just a tiny fraction (roughly 0.07%) of the 5.79 million DFAXes for this case, most of which are essentially zero. The DFAXes with higher values are for outaged branches that are more tightly coupled to monitored branches. The fewer tightly coupled outaged/monitored branch pairs, the less failures will propagate, all else being equal. This "good news" presented in Figure 3 means that the EHV system, by its nature and due to how it is planned, is highly immune to cascading. The outage of one branch threatens only, at most, a few others. This is one reason why we have so few cascading blackouts. Indeed, the study by Bhat et al., which went beyond the DFAXes to compute the postoutage flows, as do our metrics as well, also showed that most of the exhaustively selected single and double contingencies will not cause overloads.

Second, the three distributions in Figure 3 are for the 2012 and 2016 summer high-demand cases and the 8 September 2011 preblackout case, respectively, as listed in Table 5. Although they are close together, to the naked eye, the middle curve (2012 case) clearly has more higher-value DFAXes than does the lower curve (2011). The upper curve (2016 case) also has more higher-value DFAXes than does the middle curve. In fact, the 2016 distribution has 30% more large DFAXes (≥ 0.7) than does the 2011 distribution, which is a significant difference. This "bad news" shown in Figure 3 seems to suggest that the natural growth of the system leads to tighter coupling and a greater risk of cascading, all else being equal.

Why would this happen? Generally, network upgrades are made to accommodate an increased flow of power through the grid. It seems that increasing the grid's ability to transmit power also makes it more able to transmit failures. This is true even for the SW WI, with its relatively low demand

table 5. The WI cases studied (the data in this table are for the SW region only).

Case	Demand/Generation (MW)
2016 summer high	62,691/57,578
2016 spring high	44,229/40,472
2016 winter high	38,931/36,085
2016 winter low	27,530/30,500
2016 summer low	34,577/32,010
2011 preblackout	51,619/46,752
2012 summer high	61,933/57,841

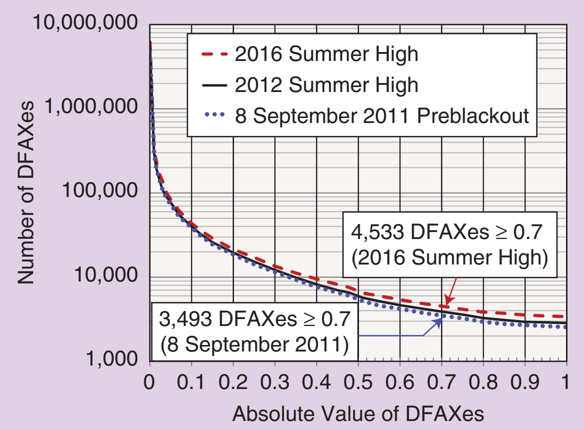

figure 3. DFAX distributions for the SW WI.

growth (see Table 5) and hence its relatively few upgrades to the EHV network from year to year.

DFAXes, although interesting, do not reflect the pre- and postcontingency flows on the network. The stress metrics do, however, and are much more informative, as we will show in the next section.

System Stress Metrics and Operating States

The four main columns of Table 6 show four system metrics: sampling vulnerability (RankV and DegreeV under the tan heading) and criticality (RankC and DegreeC under the blue heading) for the various cases and *for the entire SW WI*, instead of for individual branches. The network metrics are summations of the branch metrics in each case. The three colored rows highlight the cases with the highest values of stress.

Most branches have a RankV < 1 for the six cases presented. That is, for most contingencies, the postcontingency flows are less than the ratings for most of the monitored branches. Nonetheless, consider the vulnerability columns. The 2016 summer high-demand case has 259 monitored branches with a RankV ≥ 1, that is, they are "overloaded" with postcontingency flows equal to or greater than their ratings. Because this case has 4,849 branches, 5.3% of them are vulnerable to such postcontingency overloading, the other 95% are not. Approximately 108 (2.2% of the 4,849) of these branches are particularly vulnerable, with postcontingency overloads for two or more contingencies.

Consider now the two criticality columns for the same 2016 summer high-demand case. For each of 309 critical outages (6.4% of the total 4,849 branches), at least one monitored line becomes overloaded to or above its rating. Roughly 89 branches (1.8% of the total 4,849 branches) are particularly critical: the outage of any of them would cause at least two monitored lines to overload.

These stress metrics are highest (worse) for the highlighted cases: high-demand summer (HS) 2016, high-demand spring (HSP) 2016, and before the 8 September 2011 Arizona/Southern California blackout. Knowledgeable engineers assessed separately what they considered to be the relative risk to cascading of the various cases based on demand, internal generation, imports, and seasonal maintenance practices. Their informal risk judgment is listed in the next-to-last column of Table 6. Note that their judgments of relative risk and the four stress metrics concur, with two minor exceptions.

The differences in the four stress metrics, compared case to case, are mostly in the first significant figure. The values of the four metrics for the most stressed case, 2016 summer high demand, are roughly twice the values for the second most stressed case, preblackout 2011. And the metric values for the preblackout 2011 case are much higher, approximately double for three of the four metrics than for the values for the next case, the HSP 2016. Most of the metrics are similarly distinct and consistent for the three low-stress cases. There is nothing subtle about the results of the stress analysis; the metrics clearly and consistently signal real differences in stress.

The threshold value for the computation of the metrics is a choice left to the analyst. As noted in the text and on the tables, Tables 6 and 7 use 100% of branch ratings as degree thresholds. Tables 3 and 4 used 75% of the branch ratings. Cascading has occurred with postoutage flows below the branch ratings, as in the 1965 and 2003 U.S./Canada cascading blackouts discussed previously. Cascading has also not occurred although the ratings were exceeded. If the threshold is too low, false positives will appear. If it is too high, problems may be overlooked. Like focusing a microscope, a reasonable

table 6. The number of stressed branches and the percent of all the branches in the SW WI region.

Cases	Vulnerability				Criticality					
Season/ Demand	RankV ≥ 1 (DegreeV ≥ 1)		DegreeV ≥ 2		RankC ≥ 1 (DegreeC ≥ 1)		DegreeC ≥ 2		Informal Risk Judgment	Branches SW WI
Summer 2016										
High	259	5.3%	108	2.2%	309	6.4%	89	1.8%	Highest	4,849
Low	38	0.8%	4	0.1%	41	0.9%	1	0%	Low	4,785
Winter 2016										
High	51	1.1%	6	0.1%	49	1.1%	5	0.1%	Medium	4,534
Low	26	0.6%	4	0.1%	24	0.5%	2	0%	Lowest	4,563
Spring 2016										
High	109	2.4%	34	0.7%	96	2.1%	14	0.3%	High	4,553
8 Sept. 2011	126	3.1%	63	1.5%	183	4.5%	27	0.7%	Preblackout	4,096

Thresholds = 100% of ratings for degree metrics.
The highest-stress metrics (by number and %) are highlighted in green.

threshold easily can be found empirically when analyzing a system's metrics.

Planners and operators could identify the high-vulnerability branches and look for ways to reduce vulnerability, as higher stress means a higher risk of cascading. They could also study the highly critical branches: some outages could cause especially high postoutage flows. A few of these outages are serious for a different reason, as they may affect many other branches. Other useful ways to look at the metrics are illustrated in the next section.

Preblackout Stress Metrics: 8 September 2011

The cascading blackout of 8 September 2011 began with a switching error in the North Gila substation. A technician carrying out a complex series of operations was distracted momentarily and incorrectly marked his checklist. His out-of-sequence next operation tripped the 500-kV Hassayampa-North Gila line, which had tripped frequently and recently without cascading. But on 8 September, the SW WI was highly stressed (Table 6). This time, the 500-kV outage caused both Coachella 230-kV/92-kV transformers of the Imperial Irrigation District (IID) to overload and trip. The single-outage event became a three-outage event, and further cascading blacked out much of the SW WI.

The WECC created a reconstruction of the system state before the blackout. We computed the metrics for this preblackout state. See Table 6 and for more detail Table 7, where each row corresponds to an area within the SW WI. The SW WI precascading stress (the 8 September 2011 row in Table 6 and the last row in Table 7) was high compared to the 2016 stresses and second only to the HS 2016 case. In Table 7, the columns have exactly the same meaning as explained for Table 6. The rows (areas) where the stress was highest are highlighted: 7.5% of the IID branches (Table 7, area 2) had a RankV ≥ 1, double the SW WI average. Six IID branches, including the Coachella transformers, were vulnerable for two or more single outages. The cascading began in Arizona (area 1), where many critical SW WI branches were found, including the Hassayampa-North Gila line. (Arizona and the IID were named in the postmortem report. The other areas may not be named.)

Area 7, also highlighted, was highly vulnerable and was the most critical in SW WI. An area being highly stressed does not mean that cascading will start there or will even occur. The cascading did not start in area 7. Stress is a necessary, but not sufficient, condition for cascading to occur—the necessary procedures failure occurred in areas 1 and 2 (see Table 1).

Very Large System Study

The 2016 operations planning model of all of the WI had roughly 26,400 branches. In a further study, essentially all of the nonradial branches in the 21 areas making up the WI were outaged one by one and monitored for each outage. (In contrast, normal planning and operating studies are done for smaller subsystems.) Stressed areas, especially, were identified, and the analysis led to remarkable observations specific to very large systems.

Regarding vulnerability, three large areas had almost half of all the WI's branches with postoutage flows that exceeded the branch ratings (a RankV> 100% of ratings). The areas represented a large cluster of vulnerability, although their percentage of vulnerable branches was typical of the entire WI.

Regarding criticality, two of the three aforementioned areas had relatively typical criticality metrics. The third had 455 branch outages with a RankC greater than the monitored line ratings. Almost one-third of the critical branches in the

table 7. The precascading metrics in seven SW WI areas (upper rows) and their totals (bottom row) for 8 September 2011. The number of stressed branches and the percent of all the branches.

	Vulnerability				Criticality				
SW WI Areas	RankV ≥ 1 (DegreeV ≥ 1)		DegreeV ≥ 2		RankC ≥ 1 (DegreeC ≥ 1)		DegreeC ≥ 2		Branches Per Area
1	39	2.5%	25	1.6%	73	4.7%	7	0.5%	1,542
2	10	7.5%	6	4.5%	7	5.2%	1	0.7%	134
3	0	0%	0	0%	1	0.4%	1	0.4%	272
4	4	1.6%	2	0.8%	4	1.6%	0	0%	255
5	6	1.2%	2	0.4%	14	2.8%	0	0%	506
6	6	1.5%	1	0.3%	11	2.8%	4	1%	397
7	62	5.9%	28	2.6%	75	7.1%	15	1.4%	1,057
Total	126	3.1%	63	1.5%	183	4.5%	27	0.7%	4,096

Thresholds = 100% of ratings for degree metrics.
A few branches are in two or more areas. They are counted in each area but just once in the bottom-row totals.
The highest-stress metrics (by number and %) are highlighted in green.

Cascading is an event where a first outage causes one or more outages in a second stage and so on, eventually causing a system to collapse.

WI were in this area, with more than half (339) of the highly critical WI branches having a DegreeC ≥ 2.

Three abutting areas in another region had the highest percentage of vulnerable branches within the WI. None was in the group discussed above. Two of these areas also had the highest percentages of critical branches in the WI. Two other areas in the same region also had high percentages of critical branches. In other words, this region was doubly stressed by being both highly vulnerable and highly critical. Clearly, the stress problems are different for different parts of the system. The study raised the following issues that are beyond the purview of normal analyses done by transmission service operators:

- ✔ How should the problems identified by the metrics affect system planning or operations?
- ✔ Why are some areas very critical?
- ✔ Why does the system have 74% more critical branches than vulnerable ones?
- ✔ Why are some areas critical but not particularly vulnerable, while other areas are more vulnerable?
- ✔ Which areas are most vulnerable to other particularly critical areas, and why?
- ✔ How can one make areas inherently less critical or less vulnerable?

There were more than 600 million DFAXes in the aforementioned study—a daunting number. But, the stress metrics provide a remarkable tool to use when assessing the risk of blackouts. On an ordinary laptop, the computation of the metrics took on the order of minutes once the DFAXes were computed and stored. New ways of thinking will be needed to answer questions like the ones raised in this section.

Adequacy and Implications of Stress Metrics

Adequacy of Stress Metric

Two fundamental issues may seem to have been overlooked in our work. First, nonlinear effects like voltage collapse and instability are often involved in cascading. The branch and path flows are expressed in terms of their limits in megawatts, but the megawatt limit of a branch or path is determined by the most restrictive issue, whether thermal, voltage, instability, and so on. The nonlinear problems generally occur as a result of high-megawatt loading, so measuring stress in terms of megawatts does not ignore the nonlinearities.

Finally, full ac-contingency analysis models voltages. It may be used instead of DFAX analysis and is only slightly more time-consuming. We emphasize the DFAX approach in part to highlight the fact that the cascading failure network differs from the traditional Ybus network. Also, a single set of DFAXes is valid for studies of changes in generation and demand, whether these are drivers of changes in stress or possible mitigation actions.

Second, the metrics are the results of first-contingency analyses. Cascading is an event where a first outage causes one or more outages in a second stage and so on, eventually causing a system to collapse. How can the metrics work without simulating secondary contingencies? The answer is that it is not only impractical to simulate all possible double contingencies, for instance, but only a tiny fraction of them lead to cascading. We found the multiple-contingency study by Bhatt et al. to be very useful, but we do not think that they want to do this in real time or for planning studies. It is too much work for too little information and is not needed to measure stress, a necessary condition for cascading to occur.

Which Metric Is Best?

Each metric evaluates stress in a different way. None has been shown to be best. Correlation analysis reveals mostly low correlations among the metrics. It is reasonable for the stress of a complex system to be multifaceted. Furthermore, four metrics are not too many to track, and combining them into a single metric would reduce information unnecessarily. As an analogy, consider that medicine also uses a vector of four or five stress metrics, called *vital signs*. It is more useful to know that "the pulse is quite high, but everything else is normal," rather than "the weighted sum of all the vital signs is a bit above normal."

Some Practical Issues

As demand and generation grow, transmission systems expand to increase transfer capability. Previous work has shown that this growth may increase stress. The increase from year to year of the large DFAXes mentioned previously seems to support this observation. As the system is reinforced to allow for more power to be transmitted, the ability of failures to spread may also increase.

An important topic is how operators and planners may reduce stress, but it is beyond our present scope. We have shown only how to quantify stress, a necessary condition for cascading to occur. The metrics provide a new tool to operators and planners to quantify and analyze a system's stress and forestall cascading.

How could diagnosing and reducing stress have prevented previous cascading failures? The SW WI on 8 September 2011 was highly stressed, approaching the HS 2016 base case, which is extreme. It is not clear that the operators knew this. They might have taken precautionary actions identified in the postmortem report. The metrics identified the vulnerable and critical areas and branches. Knowing that the Hassayampa-North Gila line was highly critical *today*, operators could have postponed the complicated switching and other sensitive operations at North Gila. Increasing generation or reducing demand in the Imperial Valley, as well as other available options, would have reduced the vulnerability and criticality and could have prevented the blackout.

Nonetheless, we believe that the real solution will *not* be to present the operators with 126 vulnerable branches or 183 critical ones (Table 7), which they will have to do something about in real time. These metrics are just very good indicators of stress. We believe that the power system of the future will not be made more robust by patches but by being planned and operated in ways not currently recognized that are inherently less stressful and without increasing its reliance on inherently failure-prone ancillaries.

Satisfying NERC Criteria

Today's NERC criteria have not proved sufficient for preventing all cascading events, but they are the law in the United States, and similar criteria are applied elsewhere. The following stress metrics can be used:

- ✔ as a screening tool for identifying certain contingencies that are worth examining for possible cascading
- ✔ to provide documentation for ignoring others
- ✔ to apply the NERC and other criteria more effectively in other ways.

Summary and Conclusions

We have presented advances on the prevention of cascading blackouts, the oldest major unsolved technical problem in power systems. We introduced a new cascading failure network. Four metrics quantify stress, a necessary condition for cascading to occur. The network and metrics are new applications of well-known and accepted tools. We studied the WI of North America using utility data for different seasons and demands. The metrics are consistent with intuitive assessments of stress for this system. The metrics, applied to the pre-event state of a major cascading blackout, showed that the system was highly stressed, especially in the areas and circuit elements where cascading developed. The metrics are practical measures of stress that can be rapidly computed, even for large systems. The proper use of these metrics will identify a system's susceptibility to cascading, beyond pinpointing the most vulnerable and critical branches and areas, and should help spot incipient cascading before it occurs. The metrics provide a way to meet NERC planning study requirements more fully and point to ways to make fully functioning and undamaged systems inherently more immune to cascading blackouts.

Acknowledgments

We gratefully acknowledge the management and engineers of the WECC for providing financial support, technical assistance, and sensitive data and for allowing the results to be published. Their commitment to fighting blackouts is evident. We especially salute, with gratitude, the contributions of Donald G. Davies, former WECC chief senior engineer. The conclusions are our own, but the WI study would not have been possible without the support of the WECC.

For Further Reading

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Biographies

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Robert D. Barnett

energy in Niagara Falls

International Niagara Commission

In previous "History" columns, interesting aspects of electrical power associated in the Niagara Falls area were explored. Past articles include:

- "The Niagara Alternators: Competing Alternatives and Frequencies" by R.D. Barnett (vol. 16, no. 5, 2018)
- "Canada-U.S. ac Intertie: First Canadian Hydro Plant at Niagara Falls" by C.A. Woodworth (vol. 14, no. 4, 2016)
- "The Schoellkopf Disaster: Aftermath in the Niagara River Gorge" by C.A. Woodworth (vol. 10, no. 6, 2012)
- "25-Hz at Niagara Falls: End of an Era on the Niagara Frontier, Part I and Part II" by T.J. Blalock and C.A. Woodworth (vol. 6, nos. 1 and 2, 2008)
- "Triumph of AC: From Pearl Street to Niagara" by C.L. Sulzberger (vol. 1, no. 3, 2003).

In this issue, we present a summary of events leading up to the choice of electricity to transport the hydro energy of Niagara Falls to its end users by exploring the work of the International Niagara Commission.

We welcome back Robert D. Barnett for a fourth time to these "History" pages. A Life Member of the IEEE, Barnett graduated from the University of Waterloo and Niagara College. In 1982, he formed the Niagara Society for Industrial History as a support group for a proposed museum in a former Niagara Falls power plant, and he has written on the history of this topic.

John Paserba
Associate Editor, "History"

IN 1883, THOMAS EVERSHED, A recently emigrated English civil engineer, was hired by the State of New York to survey the Niagara Reservation. The reservation was intended to protect the area around the falls from being overrun by industrial development. Evershed realized that the reservation would restrict the expansion of power development to the High Bank area below the falls. To use the area above the falls, some unconventional means of water delivery would be needed.

Figure 1 shows the Niagara Mill District at the High Bank in 1893. Other than some small dc generators used for street lighting and trolley car service, the bulk of the power supplied was in the form of on-site, hydraulic turbine direct-drive mechanical power. Figure 2 is a 1949 U.S. Geological Survey map showing the New York State Reservation in green. This is a close approximation to the reservation as it was in the 1890s.

The Evershed Plan

In 1886, Evershed proposed a scheme to allow development above the falls. Water was to be diverted from the Niagara River by means of a canal about a mile above Goat Island. This canal would then distribute the water to various mill sites along its length. The spent water would be carried away by a tunnel to the Niagara River, discharging at a point just upstream from the Rainbow Bridge. Although initial attempts to raise capital were not successful, several banking firms in New York City eventually showed interest. They agreed to organize the Cataract Construction Company to oversee the preparation of plans and act as the financial agent.

Evershed's plan called for 12 inlet canals bringing water from the Niagara River to wheel pit sites where manufacturing firms would be established. Originally, there were to be 238 *wheels*, or turbines, set at the bottom of a number of pits (see Figure 3). Each wheel would produce 500 hp. The industries that were to become the tenants of the power company would develop around these wheel pit sites. Power would be distributed in the form of flowing water in much the same manner as that of Lowell, Massachusetts.

In 1837, the Proprietors of Locks and Canals on the Merrimack River, the supervising authority for water

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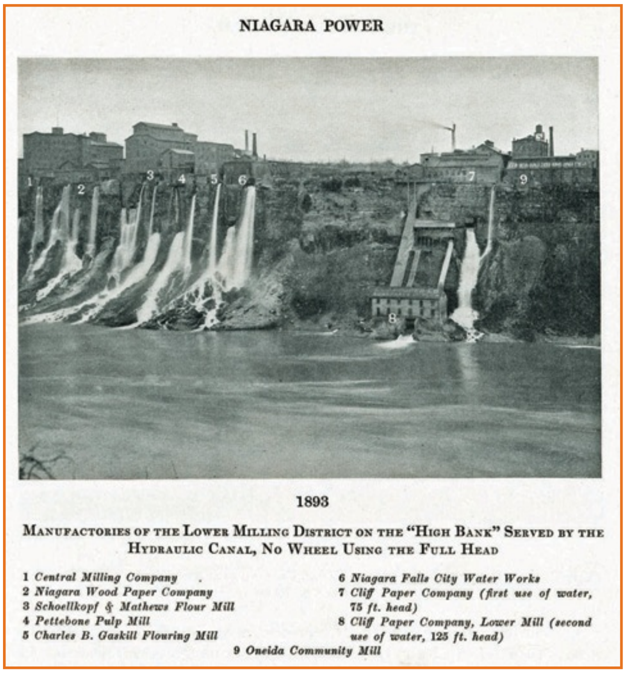
power in Lowell, Massachusetts, hired James B. Francis to improve the efficiency of the turbines then in use. By 1851, Francis had conducted nearly 100 experiments related to water flow and turbine efficiency. These experiments brought the practice of American turbine engineering from a cut-and-try art to an applied science. As a result, Lowell became established as one of the world's major manufacturing centers. All this occurred with the use of mechanical power alone. The Francis turbine is still in use in hydroelectric plants around the world.

The major drawback of the Evershed plan was the cost of excavating the sub-surface rock. In an attempt to reduce costs, the number of wheel pit sites was reduced several times. Figure 4 shows one of these versions. The entrance to the canal is shown at point H, near Connor's Island. Figure 5 is a vertical section showing the wheel pits and the tail race tunnel that was to remove the spent water. In all of its incarnations, the Evershed plan was that of a decentralized power generation scheme, typical of the times.

Because of the high cost of excavation, Cataract officials were reluctant to go ahead with the Evershed plan in any of its forms. They also felt that local tenants of the power company would not be numerous enough


NIAGARA POWER

1893

MANUFACTORIES OF THE LOWER MILLING DISTRICT ON THE "HIGH BANK" SERVED BY THE HYDRAULIC CANAL, NO WHEEL USING THE FULL HEAD

1 *Central Milling Company*
2 *Niagara Wood Paper Company*
3 *Schoellkopf & Mathews Flour Mill*
4 *Pettebone Pulp Mill*
5 *Charles B. Gaskill Flouring Mill*
6 *Niagara Falls City Water Works*
7 *Cliff Paper Company (first use of water, 75 ft. head)*
8 *Cliff Paper Company, Lower Mill (second use of water, 125 ft. head)*
9 *Oneida Community Mill*

figure 1. The Niagara Mill Bank at High Bank in 1893. (Source: E.D. Adams, *Niagara Power*, vol. 1. Niagara Falls, NY: Niagara Falls Power Co., 1927, p. 72.)

to make the venture profitable. After all, they were looking at a total of over 100,000 hp, an amount not previously developed at one site. It was generally agreed that, to be profitable, power developed at Niagara Falls would have to be transmitted to Buffalo, New York, 20 mi distant. And to complicate matters, it wasn't a foregone conclusion that the transmission means should be electricity.

Edward Dean Adams

One of the Cataract officials was a New York lawyer named William Rankine. Rankine was an associate of J.P. Morgan, the wealthy New York financier. He approached Morgan for financial support, but Morgan was dubious. Morgan felt that the Cataract Construction Company had no one at the helm whom he could trust. Finally, he told Rankine that if Edward Dean Adams could be persuaded to lead the company, Morgan would back the enterprise.

Adams was Morgan's most successful business negotiator, and he soon came to the conclusion that more information was needed before he could make a commitment. He asked Coleman Sellers, a prominent mechanical engineer, for his opinion. On 17 December 1889, Sellers traveled to Niagara Falls and subsequently sent Adams a report detailing costs and suggested modifications. Sellers was cautious but enthusiastic. This enthusiasm for the plan went a long way toward convincing Adams and the other New York investors. As a result, they invested more than US$2.5 million in the Cataract Construction Company.

Adams realized that he needed to seek the advice of the best engineering minds of the time. Edison was one of the first to be consulted, and to no one's surprise, he proposed dc transmission. One might have expected Westinghouse to propose ac, but he suggested compressed air. Compressed air was already being used as a means of power transmission in Europe. In the late 19th century, the French, Italians, and Swiss were well versed in water power development and had several power generation projects in progress. Ferranti's Deptford Station, using single-phase ac, was also under construction in London. With the idea that the solution may lie overseas, Adams traveled to Europe in February 1890.

After an extensive examination of projects and people, Adams sent a telegram to the Cataract Construction Company declaring European practices to be far ahead of American ones. He recommended that construction contracts be deferred until more information could be obtained. On 8 June 1890, Adams telegraphed that he was convinced that

figure 2. A 1949 map of Niagara Falls, New York. (Source: U.S. Geological Survey.)

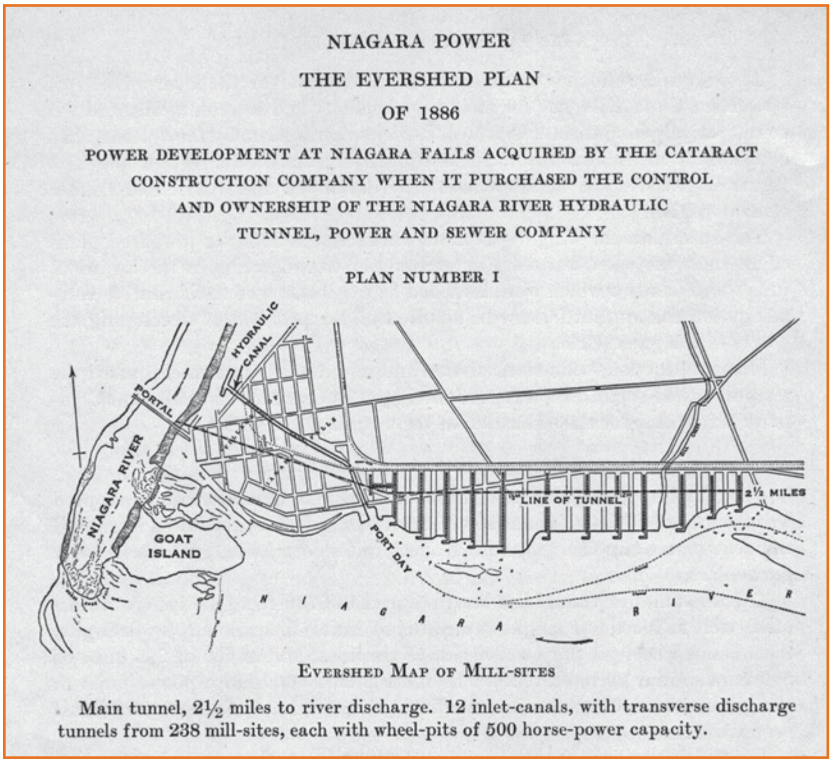


figure 3. An early Evershed plan. (Source: E.D. Adams, *Niagara Power*, vol. 2. Niagara Falls, NY: Niagara Falls Power Co., 1927, p. 10.)

forming an international commission was the best course. Sellers agreed. The side canals of Evershed's scheme were to be abandoned and the tunnel shortened to no more than 8,000 ft.

A meeting was held on 18 June 1890 in Adams' London apartment at Brown's Hotel. Adams pointed out that, in Europe, power generation was not distributed over a long series of inlet canals but was concentrated. He believed that at Niagara Falls, power should be generated at one place and transmitted to the factories on Cataract

> One might have expected Westinghouse to propose ac, but he suggested compressed air.

Construction Company land as well as to the towns of Tonawanda and Buffalo.

The means of transmission was still to be determined. Adams expected that, in addition to electricity, transmission could be by "rapidly running cables, by hydraulic power, or by compressed air."

European Developments

The Europeans were transmitting power using hydraulic (pressurized water) systems, compressed air, fuel gas, wire ropes, and steam. From our perspective more than a century later, it is difficult to appreciate how humble the position of electricity was as a means of power transmission. A closer look at the competing systems will help us to appreciate what Adams and his cohorts were up against.

- ✔ Steam was the power transmission medium with which engineers were most familiar. By 1890, steam engines were a mature technology. They were being improved continuously (the valve gear designed by Corliss is an example of this), but their losses were tremendous. A high-efficiency steam engine boiler system seldom exceeded 20%, but the design and operating principles were well understood by engineers. This was certainly not the case with electricity, particularly ac. Steam's low efficiency limited its power transmission distance to a few hundred feet at most.
- ✔ Fuel gas was considered because of the extensive use of manufactured gas for both lighting and gas engine applications. Because of this, gas was cheap to produce. However, leakage of gas at the many

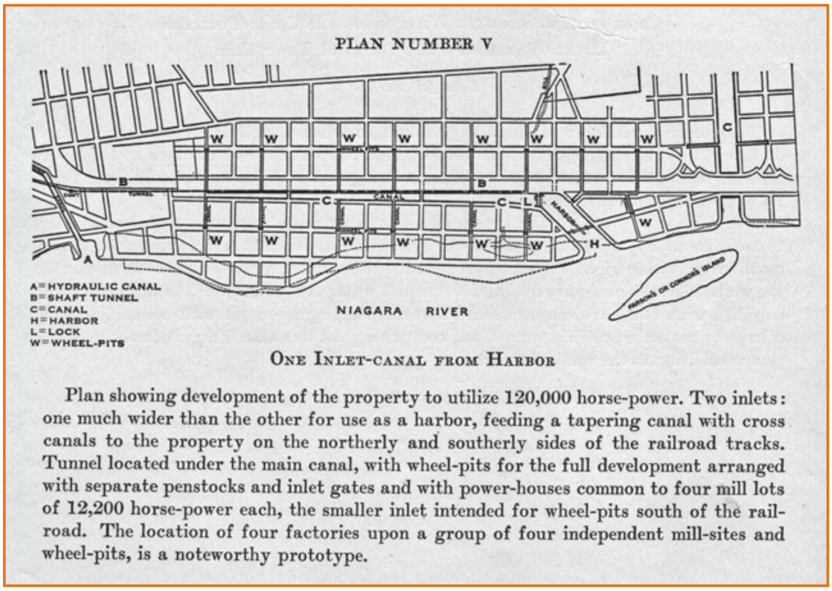


figure 4. A later modification of the plan. (Source: E.D. Adams, *Niagara Power*, vol. 2. Niagara Falls, NY: Niagara Falls Power Co., 1927, p. 14.)

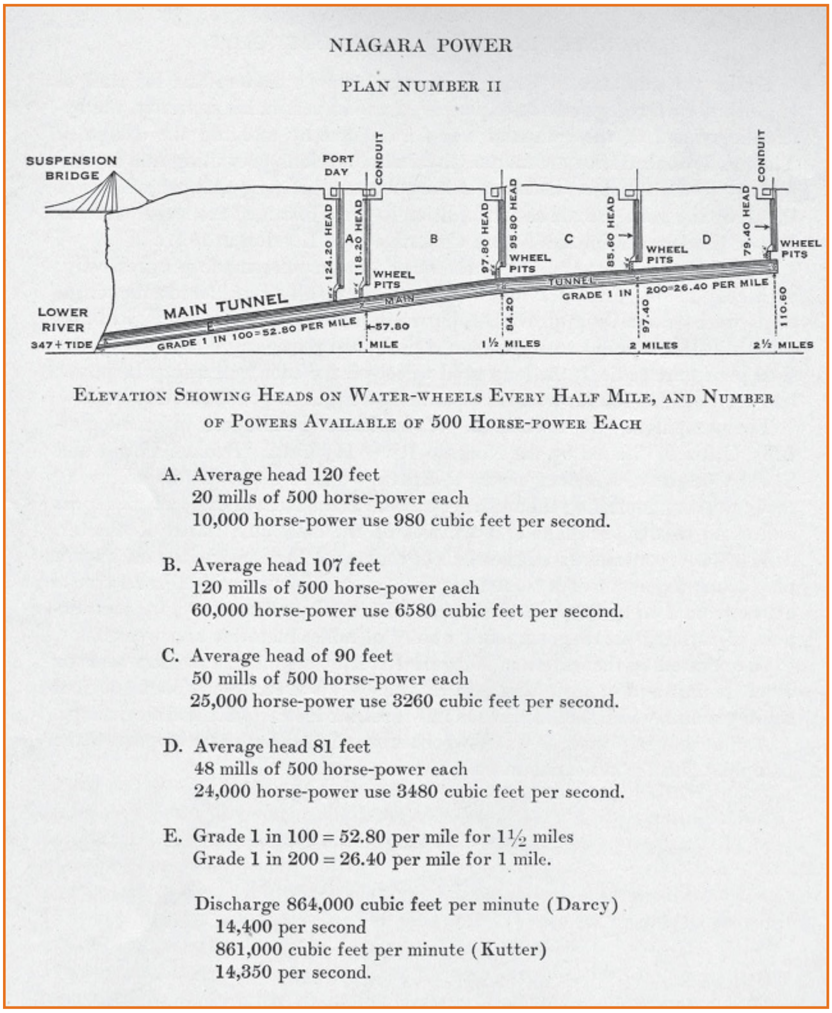


figure 5. A cross section of the wheel pits. (Source: E.D. Adams, *Niagara Power*, vol. 2. Niagara Falls, NY: Niagara Falls Power Co., 1927, p. 12.)

joints in the pipes was a serious fire hazard. Maintenance of the system was high. As a general-purpose medium, it was not seriously considered.

It is difficult to appreciate how humble the position of electricity was as a means of power transmission.

- ✔ Wire rope, also known as telodynamic transmission, was in use over distances of several miles in Europe. The use of ropes and pullies had been in widespread application inside mills to transmit the power of a steam engine to the mill machines. When the system was intended to transmit power in blocks of thousands of horsepower, then the size and speed of the cables became prohibitive. The need to return service quickly after a cable breakage was another problem.
- ✔ Hydraulic systems were in use in several European cities, including London, Antwerp, and Geneva. But the transmission distances were short and the amount of power transmitted small, compared to the thousands of horsepower to be generated at Niagara Falls. The London Hydraulic Power Company's total output was approximately 7,000 hp. In addition, the hydraulic working fluid used today is a special mixture of oils, but in the 1890s, the fluid was water. Freezing was a problem as was corrosion.
- ✔ Compressed air transmission to Buffalo was viewed as a viable alternative to electricity. Many

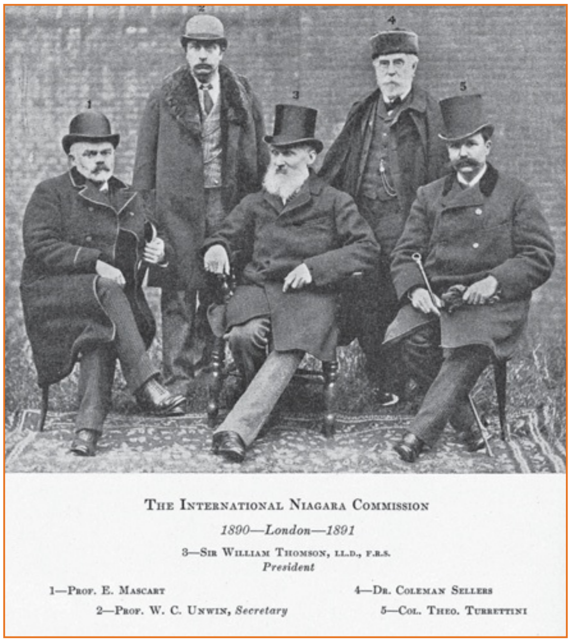


figure 6. The International Niagara Commission. (Source: E.D. Adams, *Niagara Power,* vol. 1. Niagara Falls, NY: Niagara Falls Power Co., 1927, p. 180.)

felt that it would be cheaper than electrical transmission because it could be introduced into factories for use in their existing steam engines without abandoning anything more than the boilers. Because of his strong position in the business of manufacturing air brakes for railroad trains, Westinghouse had considerable experience in this area.

In 1878, Robert Zahner, writing in *The Transmission of Power by Compressed Air*, said:

> For transmitting power to great distances, shafts, belts, friction-wheels and gearing are clearly out of the question. The practical incompressibility and want of elasticity of water, renders the hydraulic method unfit for transmitting regularly a constant amount of power. …Whether steam, air or wire rope is to be made the means of transmitting power from the prime mover to the machine, depends entirely upon the special conditions of each case. The wear and tear of cables lessen the advantages of the telodynamic transmission. Steep inclinations and frequent changes of direction of the line of transmission often exclude

	table 1. A summary of proposals.					
	Distribution and Transmission					
	AC	DC	PNEU	TELO	HYD	Proposal Submitters
1		X				Cuenod, Sautter & Co. with Faesch and Piccard, Switzerland
2		X				Prof. Vigreux and M. Leon Levy, France
3		X				M. Hillairet and M. Bouvier, France
4			X			Prof. Riedler and M. Victor of Germany and France
5		X				G.F. Deacon and Siemens Brothers, England
6			X		X	H.D. Pearsall, England
7	X		X			Prof. Lupton and Mr. Sturgeon, England
8	X					Ganz and Co., Hungary
9	Turbines only: no electrical					Escher, Wyss & Co., Switzerland
10			X	X	X	J.J. Rieter & Co., Switzerland
11					X	Prof. Vigreux and M. Leon Feray, France
12	X		X		X	Pelton Water Wheel Co., United States
13	X					Prof. George Forbes, England
14			X			Norwalk Iron Works, United States

Note: AC is single phase in all cases. PNEU: pneumatic system; TELO: telodynamic system (wire rope); HYD: hydraulic system.

its adoption. In carrying steam to great distances very important losses occur from condensation in the pipes. Compressed air is the only general mode of transmitting power; the only one that is always and, in every case, possible, no matter how great the distance nor how the power is to be distributed and applied. But compressed air is also a storer of power, for we can accumulate any desired pressure in a reservoir situated at any distance from the source and draw upon this store of energy at any time; which is not possible either in the case of steam, water or wire-rope.

Because of this view, it was initially believed that a second powerhouse was required at Niagara; it would be a hydropneumatic station.

The International Niagara Commission

Adams called his group of experts the International Niagara Commission and convinced Sir William Thompson to be its head (see Figure 6). The International Niagara Commission consisted of the following luminaries:

- ✔ William Thomson, president of the commission, was a Fellow of the Royal Society. A mathematical physicist and engineer, he was an electrical expert who was knighted Lord Kelvin for his work on the transatlantic telegraph project. He is probably best known for determining the correct value of absolute zero, whose units are stated in kelvins in his honor. He was originally a strong opponent of ac.
- ✔ Coleman Sellers, a prominent American consulting engineer, was a past president of the American Society of Mechanical Engineers, professor of mechanics at the Franklin Institute, professor of engineering practice at the Stevens Institute of Technology, and an inventor who had obtained more than 30 patents, most dealing with mechanical power transmission.
- ✔ Éleuthère Mascart, professor and later chairman of general and experimental physics at the College of France, went on to become president of the Académie des Sciences and vice president of the British Institution of Electrical Engineers, the first foreigner to hold the position.
- ✔ William Unwin, a British civil and mechanical engineer, Fellow of the Royal Society, and president of both the Institution of Civil Engineers and the Institution of Mechanical Engineers, was noted for his extensive work on hydraulics and steam engines.
- ✔ Theodore Turrettini, a consulting hydraulic engineer, was a colonel of artillery in the Swiss Army, president of the city of Geneva, and a director of the Swiss Society of Physical Instruments. He was also a member of the Franklin Institute and responsible for hydroelectric power stations on the Rhone River and elsewhere.

The Commission produced a letter of invitation stating in part (Adams, vol. 1, p. 183):

> You are therefore invited to submit projects for the development, transmission and distribution of about 125,000 effective horsepower on the shafts of water motors at the Falls of Niagara, to the consideration of an International Niagara Commission, holding its sessions at Central Institute, Exhibition Road, London.

Proposals were to be filed in New York by 29 August 1890 and in London by 26 September of the same year. Table 1 is a summary of the proposals. On 29 January 1891, the commission met to consider the proposals, and on 14 February, it reached its conclusions. No first prize was awarded for a combined hydraulic/electrical project because no proposal was at a stage where it could be adopted. However, there were awards for various aspects of some proposals.

One submission by Switzerland's Faesch and Piccard did receive an award. They were subsequently awarded the contract for all 10 hydraulic turbines of 5,000 hp each. However, "none of the proposals for distribution of power was … adequate to the requirements at Niagara." Most proposals offered an electrical transmission component: four of them proposed dc, and four proposed single-phase ac. None proposed polyphase ac, although George Forbes (Proposal 13) would later be a champion of two-phase power. (See the "History" article, "The Niagara Alternators: Competing Alternatives and Frequencies," *IEEE Power Energy Mag.*, vol. 16, no. 5, pp. 96–104, Sept.–Oct. 2018).

A closer look at Proposal 1 will give some insight into the power technology of the late 1880s.

Proposal 1

The following information is taken from Adams' *Niagara Power*, volume 1. Although drawings are mentioned, it appears that they are no longer extant. We must rely on the written descriptions, and because of this, there are some problems with understanding the layout of the equipment. It should also be noted that because these were all deep wheel pit plants, serious civil engineering challenges were presented in addition to electrical ones. This proposal was in two parts. Project A was submitted first, with Project B submitted after it was realized that the tremendous amount of excavation required by Project A would make it a nonstarter.

Bidder: Cenoid, and Sautter, with Faesch and Piccard

In the information below, the generator and transmission line voltage are shown as the same value, a nominal voltage of 500 and 1600 Volts, and all dynamos are referred to as generators. In Project A, both the generators and turbines were located underground at the bottom of the wheel pit. It is not clear from the written description, but it appears that the turbines were to be in chambers and the generators in galleries off these chambers. In Project B, the generators on the upper level were connected to the turbines by a long shaft. This arrangement was the only aspect of this proposal implemented in the final design of Adams' Plant Number 1.

Project A: Underground generators with total output = 13,750 hp

✔ turbines
- quantity: 50, plus five held in reserve
- type: impulse (Girard), horizontal axis
- output: 2,500 hp @ 180 r/min driving two generators

✔ generators: two on each turbine shaft
- quantity: 100, plus 10 held in reserve
- rating: 1,250 hp @ 180 r/min
- 60 generators, plus six in reserve, rated 500 Vdc for local distribution

- 40 generators, plus four in reserve, rated 1,600 Vdc for transmission to Buffalo.

Local Distribution

Three of the galleries were to have their 60 operational generators connected in series pairs. Since we have no drawing to explain what this means, we have to take the text at face value. We are told that six generators were connected in series to give 6 × 500 = 3,000 V. From this arrangement, we have two circuits of 1,000 V and two circuits of 500 V. There were to be 10 such sets of circuits (see Figure 7).

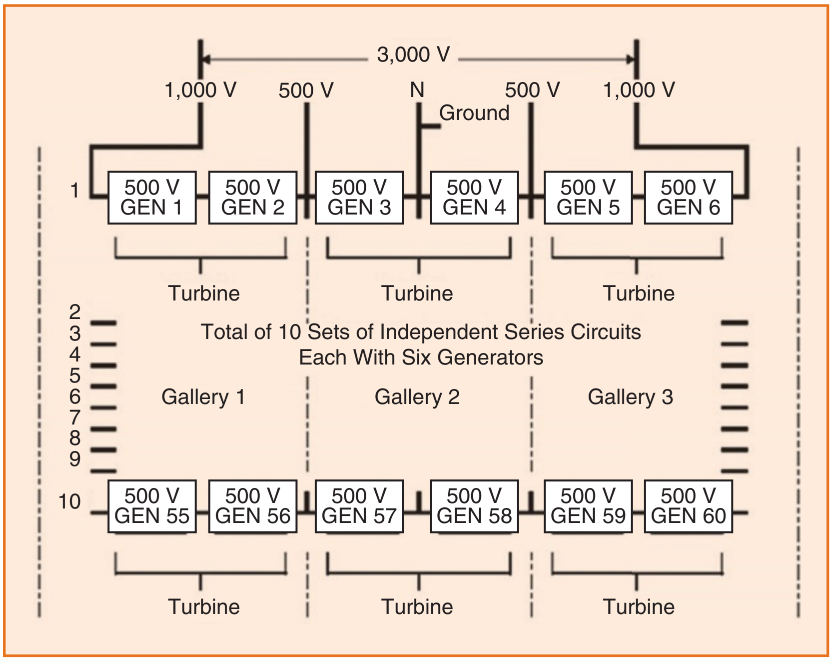


figure 7. The local distribution circuits.

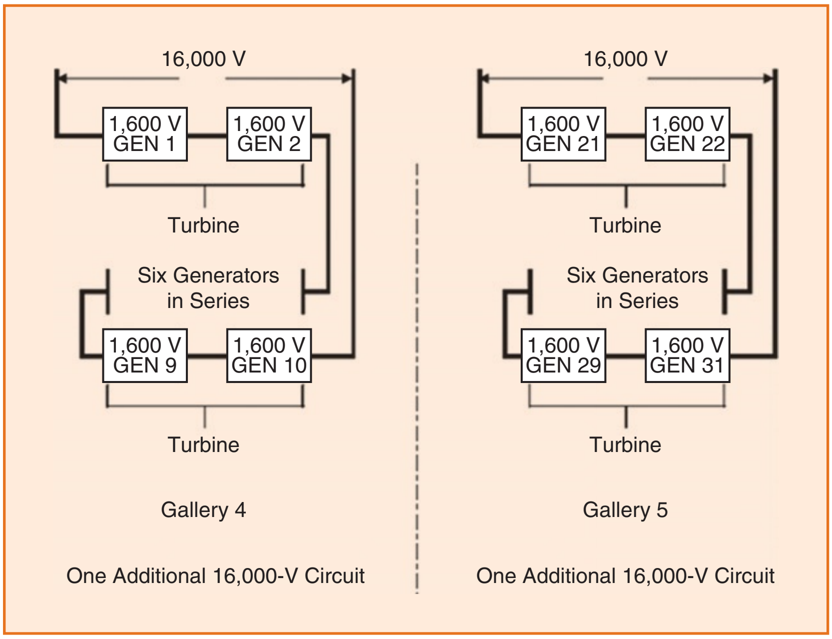


figure 8. The Buffalo transmission circuits.

The 1,000-V circuits are for "larger motors," and the 500-V circuits are for "smaller motors, electric lighting, tramways, etc." The neutral was connected to earth to limit the maximum difference to 1,500 V should a ground occur.

Buffalo Transmission

Two of the five galleries have 40 operational generators of 1,600 V with 10 generators connected in series, giving 16,000 V on each circuit. There are four of these circuits (see Figure 8).

Plant Layout

The turbines are not fed water in any operationally logical way. In *Niagara Power* volume 1, we read: "The head race-channel has five branches, one to each turbine chamber and is furnished with … electric automatic balanced sluices, which … can be closed from the galleries below." So we can take from this that there are five turbine chambers. We are also told that there are "five turbine galleries." The terms galleries and chambers seem to be used interchangeably. Regardless of the terminology, however, these headrace five branches feeding five turbine galleries make no operational sense. To remove one headrace branch would take out all of the local 500-V service or one half of the Buffalo transmission.

Project B: Above-ground generators with total output = 12,750 hp

- ✔ turbines
  - quantity: 50 plus six held in reserve, "in two parallel groups" of 28
  - type: impulse (Girard), vertical axis
  - output: 2,500 hp @ 136 r/min driving one generator
  - control: relay type governor using one flywheel per generator
- ✔ generators, one on each turbine shaft
  - quantity: 50 plus six held in reserve
  - rating: 2,500 hp, 136 r/min; see discussion of ambiguity problems below
  - 48 generators (plus four in reserve) rated 500 Vdc for local distribution

• eight generators (plus two in reserve) rated 4,500 Vdc for transmission to Buffalo.

Local Distribution
There appears to be some ambiguity in the circuit voltages and the voltages of the generators. What is shown here is a best approximation to what was intended. There are four generators of 4,500 V and 24 generators of 500 V in each of two galleries.

Buffalo Transmission
Since there were eight 4,500-V generators, two per circuit, there were four circuits feeding power to Buffalo. Four generators were in one chamber and four in the other. How any of the reserve machines were to be connected is not mentioned.

Buffalo Receiving Station
The proposal states "at Buffalo the distribution circuits are reconstituted by compensating machines." This was a fairly common practice when four-circuit dc systems were used. Even with the standard two-circuit Edison three-wire system of higher power, a compensation machine would be used to balance the voltages.

Plant Layout
In this project, the plant layout is quite different from that of Project A. The generators are all located above ground, one per turbine, in a "large horseshoe building. The head-race enters between the wings forming the sides of the horseshoe."

The layouts of the local and Buffalo circuits shown here have been developed from the written descriptions taken from Adams' *Niagara Power*, Volume 1. The arrangement of these circuits is logical from an electrical circuit standpoint.

Circuit Configuration
We need to step back and look at what was being proposed here: a high-voltage, constant-potential dc system. For both local and Buffalo circuits, in either of the projects, we have a large number of dc generators connected in series. We don't, and never really did, connect dc generators in series. There were isolated (mostly traction application) incidents of series-connected generators connected in series with a feeder to boost the voltage at a distant point. Also, when two dc generators were connected in series in the Edison three-wire system, there was a problem with voltage distribution. If one of the circuits drew more current than the other(s), then the voltage on that side would be reduced. This decreased the voltage across that generator's field, which in turn lessened that generator's armature voltage. Without some form of compensation, a large voltage imbalance would result.

This is the reason for the use of the compensating machines at the Buffalo end of the line.

But in this proposal, several machines connected in series. This was highly unusual. First, we must assume, since we are not told otherwise, that these are separately excited generators. In other words, they have their so-called shunt fields all connected in series and not connected to any one armature. Likely, these shunt fields would be connected in parallel with the total voltage produced by all the armatures connected in series. And these series-connected fields are then controlled by one rheostat (see *Dynamo Electric Machinery* in the "For Further Reading" section). Otherwise, load sharing would be a nightmare. Even with this one-rheostat setup, it would still be a bad dream. Imagine the loads changing on all of the four (or five) circuits at the same time. This would not have been a happy system.

In both Projects A and B, there is no indication as to how the reserve turbines with their generators are to be connected and switched. In fact, there is no mention of switching arrangements at all.

Other Proposals

The other proposals were along the same lines as Proposal 1 in that they used what was current practice multiplied by whatever factor was required to get to the 120,000 hp asked for by the commission. This resulted in the requirement for dozens of turbines and generators placed in a large excavation in solid rock. Some of the proposals did offer machines of 10,000 hp, but given the fact that the first Adams plant had turbines and generators of 5,000 hp, 10 times larger than the state of the art, it is unlikely that these bidders could have made good on their offer. One 10,000-hp dc generator would have been a wonderful machine to behold. Just supplying replacement brushes would have made for a very happy salesperson.

Proposal 5 from G.F. Deacon and Siemens Brothers, England, used a dc constant current system for transmitting power. Although the name Thury was not used in the proposal, the system is almost certainly that of René Thury, a Swiss pioneer in high-voltage dc transmission. In the Thury system, dc generators are connected in series and their voltage controlled to keep the current constant. In many cases, the earth was used as the return conductor, reducing the cost of transmission. Switching requirements complicated the system, however. To take a generator off line, it had to be short circuited in much the same way as most dc arc lamps were operated.

From 1889 to 1891, electrical power technology was a rapidly developing infant. Between the time of the founding of the Cataract Construction Company and receipt of the proposals, ac was becoming a viable alternative to dc for power transmission purposes. On 9 February 1891, C.E.L. Brown delivered his paper "High Tension Currents," which described his project that used 30 kVac to deliver 100 hp several miles. While the magnetic aspect of ac circuits was poorly understood and there were no easy means of solving circuit equations, there was hope.

By mid-December 1891, Adams and Sellers had become convinced that electricity would be the means of transmitting power from the new Niagara Falls Station. Still uncertain, however, was the choice between ac and dc. DC seemed to have the upper hand. In April 1892, Adams and Sellers decided to engage George Forbes as the Cataract Construction Company's electrical engineer. Forbes was a vocal proponent of ac. From that point on, the decision was inevitable. On 6 May 1893, the choice of polyphase ac was formally announced. On 5 August 1895, the first delivery of power was made to an aluminum cell of the Pittsburgh Reduction Company from unit number 1 of what was later named Adams Plant Number 1.

The International Niagara Commission had completed its work.

For Further Reading

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meet the candidates

IEEE Division delegate-elect/director-elect

BEGINNING ON 17 AUGUST, ELECTIONS will be held for the position of IEEE Division VII delegate-elect/director-elect 2021 who will serve as IEEE Division VII delegate/director 2022–2023 (the elected individual will serve as both delegate and director). Division VII consists of the IEEE Power & Energy Society (PES) only. There are two candidates, both nominated by Division VII, vying for this office: Claudio Cañizares and Lalit K. Goel. To learn more about the candidates before casting your ballot, read the biographies and candidate statements that follow.

The Candidates

Claudio Cañizares

Claudio Cañizares has held various positions at the University of Waterloo since 1993 and is currently a professor and Hydro One Endowed Chair with the Department of Electrical and Computer Engineering. He received his diploma in electrical engineering from EPN in Ecuador (1984), where he held different positions between 1983 and 1993, and his M.Sc (1988) and Ph.D. (1991) in electrical engineering from the University of Wisconsin–Madison. His professional activities focus on power systems, microgrids, energy systems, and smart grids; leading multiple grants and contracts; collaborating with industry and academics in Canada and abroad; and supervising many researchers. He has authored numerous highly cited publications, including some disclosures and patents, and has been invited to multiple institutions and conferences worldwide. He is the editor-in-chief of *IEEE Transactions on Smart Grid*, an IEEE Fellow, and a Royal Society of Canada and Canadian Academy of Engineering Fellow. He was awarded the 2017 IEEE PES Outstanding Power Engineering Educator Award, the 2016 IEEE Canada Electric Power Medal, and several IEEE PES technical council and committee awards and recognitions.

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IEEE Activities and Accomplishments

Awards and recognitions

- ✔ IEEE Power System Dynamics Committee (PSDPC) Technical Committee Working Group Recognition Awards [2020 (announced), 2019, 2017–2015, 2013, 2007, 2005]
- ✔ IEEE PSDPC Technical Committee Service Recognition Awards (2019, 2017)
- ✔ IEEE PES Outstanding Power Engineering Educator Award (2017)
- ✔ IEEE PSDPC Technical Committee Distinguished Service Award (2017)
- ✔ IEEE Canada Electric Power Medal (2016)
- ✔ IEEE PES PowerTech Conference A. Papadias Best Student Paper Award (2015)
- ✔ IEEE PSDPC Certificate of Appreciation for Outstanding Leadership (2012)
- ✔ IEEE PES Technical Council Working Group Recognition Awards for Outstanding Technical Report (2009, 2005)
- ✔ IEEE Fellow (2007).

Positions and memberships

- ✔ Editor-in-chief, *IEEE Transactions on Smart Grid* (2020–present)
- ✔ IEEE PES Awards Committee (2019–present)
- ✔ Chair, IEEE PES Electrification Magazine Steering Committee (2019–present)
- ✔ IEEE PES Lifetime Achievement Award Committee (2019–present)
- ✔ Past chair, chair, vice chair, and secretary, IEEE PES PSDPC (2013–present)
- ✔ Editor, IEEE Smart Grid Technical Activities Committee's white paper (2018–present)
- ✔ Chair, IEEE PSDPC Task Forces (2018–present, 2010–2014, 2005–2010)
- ✔ Committee liaison, IEEE PES Technical Council and New Product Development (NPD) (2018–2019)
- ✔ Editor-in-chief, *IEEE Proceedings* special issue (2018–2019)
- ✔ Member, International Program Committee IEEE PES PowerTech conferences (2018–2019, 2010–2011)

- ✔ Member, IEEE PES Outstanding Power Engineering Educator Award Committee (2017–present)
- ✔ Member, IEEE PES NPD Committee (2016–2019)
- ✔ Technical program committee (TPC) chair, IEEE PES ISGT Latin America (2016–2017)
- ✔ Member, *IEEE Proceedings* Editorial Board (2016–present)
- ✔ Chair, PSDPC task forces (2014–2018)
- ✔ Associate editor, *IEEE Transactions on Smart Grid* (2012–2014)
- ✔ Member, TPC/Advisory Committee, IEEE PES ISGT Europe (2011, 2010, 2009)
- ✔ Associate editor, *IEEE Transactions on Industrial Electronics* (2011–2012)
- ✔ Guest editor, *IEEE Transactions on Industrial Electronics* special issue (2009–2011)
- ✔ Chair and secretary, IEEE PSDPC Power Systems Stability Controls Subcommittee (2006–2011)
- ✔ Associate editor, *IEEE PES Transactions Letters* (2004–present)
- ✔ Member, IEEE PES PSDPC (1998–present)
- ✔ Member, IEEE PSDPC Power System Stability Subcommittee (1997–present)
- ✔ Member, IEEE PES Power System Stability Controls Subcommittee (1997–present)
- ✔ Chair and secretary, IEEE PSDPC Voltage Stability Working Group (1994–present)
- ✔ Contributing member, multiple IEEE PSDPC task forces and working groups (1994–present).
- ✔ IEEE Member (1987–present).

Statement

I have been an IEEE and PES member since I was a graduate student back in 1987, and ever since I have been fully engaged with and contributed to the IEEE and particularly the PES, with multiple publications and conference participations, and as a very active member and/or leader of numerous technical task forces, working groups, committees, and editorial boards. I have benefited greatly from the wealth of technical products and opportunities that the IEEE and PES offers, and in the process, I have had the opportunity to witness, learn, understand, and contribute to different aspects of the IEEE and PES technical activities and management. Based on this extensive experience and my personal knowledge of and interactions with IEEE members from all regions, I strongly believe that I can properly represent the interest of the PES and its membership at the IEEE Board and Assembly. I look forward to the opportunity and honor of representing our Society and its members at the IEEE Board, considering its large size and relevance to the Institute.

Lalit K. Goel

Lalit K. Goel is a Fellow of the IEEE and has received 20 teaching awards. He obtained his B.Tech. degree in electrical engineering from National Institute of Technology Warangal, India, in 1983 and his M.Sc and Ph.D. degrees in electrical engineering from University of Saskatchewan, Canada, in 1988 and 1991, respectively. He joined the School of Electrical and Electronic Engineering at Nanyang Technological University, Singapore, in 1991, where he is currently a professor of power engineering and director of the Renaissance Engineering Programme. He previously served as head of Power Engineering; dean of Admissions and Financial Aid; director of undergraduate education (projects) in the president's office; and director, Office of Global Education and Mobility. He served as the editor for *International Journal of Electric Power Systems Research* from 2002 to 2019. He has published 185 international journal articles and conference papers in power systems reliability, cost/benefit assessment, power markets, and renewables.

IEEE Activities and Accomplishments

- ✔ Member, IEEE PES Leadership in Power Award Committee (2019–2020)
- ✔ Member, PES Outstanding Student Scholarship Selection Committee (2020)
- ✔ IEEE PES Region representative 10 (2011–2016)
- ✔ Honorary chair, IEEE TENCON, Singapore (2016)
- ✔ Member, IEEE Region 10 Awards and Recognitions Committee (2015)
- ✔ Member, Selection Committee, IES/IEEE Joint Medal of Excellence Award (2008–2015)
- ✔ Member, IEEE PES Roy Billinton Power System Reliability Award Committee (2009–2014)
- ✔ Member, IEEE PES Outstanding Power Engineering Educator Award Committee (2010–2017)
- ✔ Editorial board member, *IEEE Power & Energy Magazine* (2011–2017)
- ✔ General chair, IEEE Region 10 Conference TENCON, Singapore (2009)
- ✔ Member, IEEE PES Long-Range Planning Committee (2007–2011 and 2016)
- ✔ Chair, IEEE Singapore Section (2007–2008)
- ✔ Member, IEEE PES Nominations and Appointments Committee (2006–2007, 2010, and 2014)
- ✔ Deputy chair, IEEE Singapore Section (2005–2006)
- ✔ Representative, IEEE PES Chapters Region 10 South (2005–2010)
- ✔ Committee member, IEEE Singapore Section (2003–2004)
- ✔ Committee member, IEEE Power Chapter, Singapore (2004–2006)
- ✔ Chair, IEEE Power Chapter, Singapore (2002–2003)
- ✔ Deputy chair, IEEE Power Chapter Singapore (2000–2001)
- ✔ Committee member, IEEE Power Chapter Singapore (1998–1999); honorary treasurer (1996–1997)

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PES meetings

for more information, www.ieee-pes.org

THE IEEE POWER & ENERGY Society's (PES's) website (http://www.ieee-pes.org) features a meetings section, which includes calls for papers and additional information about each of the PES-sponsored meetings.

August 2020

IEEE PES General Meeting (GM 2020), 2–6 August, virtual event, contact Roseanne Jones, roseanne.jones@ieee.org, http://www.pes-gm.org/2020/

IEEE PES/IAS PowerAfrica (PowerAfrica 2020), 25–28 August, virtual event, contact Mercy Chelanget, chelangat_ke@ieee.org, https://ieee-powerafrica.org/

September 2020

IEEE International Conference on Power Systems Technology (PowerCon 2020), 9–12 September, virtual event, contact Kasi Viswanadha Raju Gadiraju, kasiViswanadhaRaju.Gadiraju@ge.com, https://www.powercon2020.org/

IEEE International Forum on Smart Grids for Smart Cities (SG4SC 2020), 16–18 September, postponed to March 2021, contact Alina Schneiders, a.schneiders@academy.rwth-aachen.de

IEEE PES Asia-Pacific Power & Energy Engineering Conference (APPEEC 2020), 20–23 September, Nanjing, China, contact Li Zhang, zhanglinuaa@hhu.edu.cn, https://ieee-appeec.org/

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IEEE PES Transmission and Distribution Conference and Exposition Latin America (T&D LA 2020), 28 September–2 October, Montevideo, Uruguay, hybrid event, contact Kathy Heilman, kathy.heilman@ieee.org, https://www.ieee-tdla2020.org/

October 2020

IEEE PES Transmission and Distribution Conference and Exposition (T&D 2020), 12–15 October, Chicago, Illinois, United States, contact Carl Segneri, csegneri@mjelectric.com, http://www.ieeet-d.org/

IEEE PES Innovative Smart Grid Technologies Europe (ISGT Europe 2020), 25–28 October, Delft, The Netherlands, contact Kathy Heilman, kathy.heilman@ieee.org, https://www.isgt-europe-2020.nl/

Fourth International Conference on Energy Internet (EI2 2020), 30 October–1 November, Wuhan China, contact Chengxi Liu, liuchengxi@whu,edu,cn, https://attend.ieee.org/ei2-2020/

November 2020

IEEE Electronic Power Grid (eGRID 2020), 2–4 November, Aachen, Germany, contact info@egrid2020.org, https://egrid2020.org/

IEEE PES Innovative Smart Grid Technologies Asia (ISGT Asia 2020), 23–26 November, Perth, Western Australia, contact Farhad Shahnia, f.shahnia@murdoch.edu.au, https://ieee-isgt-asia.org/

For more information on additional technical committee meetings, webinars, and events, please visit our IEEE PES calendar: https://www.ieee-pes.org/meetings-and-conferences/conference-calendar. p&e

controllers can preschedule appliances before a hurricane hits so that energy can be stored ahead of the storm in building thermal, water thermal, battery storage, and other systems. With additional distributed energy resources (DERs), such as photovoltaics (PVs), this community could continue to operate posthurricane for hours, days, or even weeks without a major disruption of people's lives.

As an example, case study research on diversified energy resources demonstrates the resiliency of renewable energy when combined with diesel storage on a microgrid at a telecommunications facility in southern California. Figure 1 illustrates this resiliency, showing the number of outage days that the base case (generators only, shown in red) can sustain compared to a renewable energy case (generators plus solar and storage, shown in blue). In the base case, a diesel generator can power 86% of simulated outages for one–two days but only 2% of outages for two–three days. However, when the generator is combined with PV and battery energy storage systems, this system can power 98% of outages for two–three days (Anderson et al. 2017).

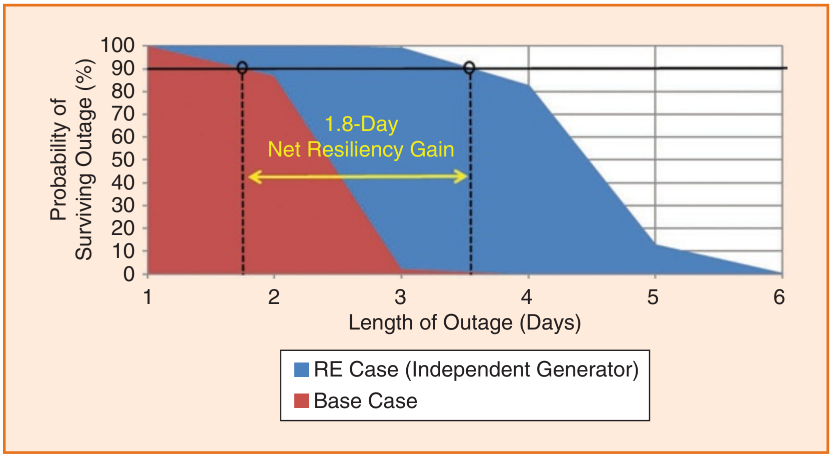

figure 1. This case study research (Anderson et al. 2017) shows grid resiliency from renewable energy resources. The use of solar energy and battery storage with diesel generators sustains power for two–three days when compared to the use of only a diesel generator, which lasts only for one–two days. RE: renewable energy. (Source: Anderson et al.; used with permission.)

Restoring the Grid Quickly With Diversified Resources

As inverter-based generation penetration levels have increased on the grid, black start with these assets has increased in importance for stronger system resilience. Power can be restored faster with wind and solar assets because their start-up times are significantly shorter than those of thermal power plants. Figure 2 shows how multiple small-asset owners can collaborate and develop hybrid black-start assets that, when pooled together, deliver enough cranking power to restart a sizable thermal generator.

These wind, solar, and storage assets do not even need to be colocated to consolidate their energy when parameters such as energy availability, losses, and controls are carefully designed. The use of DERs in disconnected microgrids, like PVs and storage, can restore power to certain numbers of customers directly. Those microgrids can then be connected regionally, and their combined power can be used for partial or full restoration of the entire grid system.

Advancing the Capabilities of DERs to Strengthen the Grid

Current advancements in grid-forming inverter control provide a strong foundation for inverter-based assets to provide

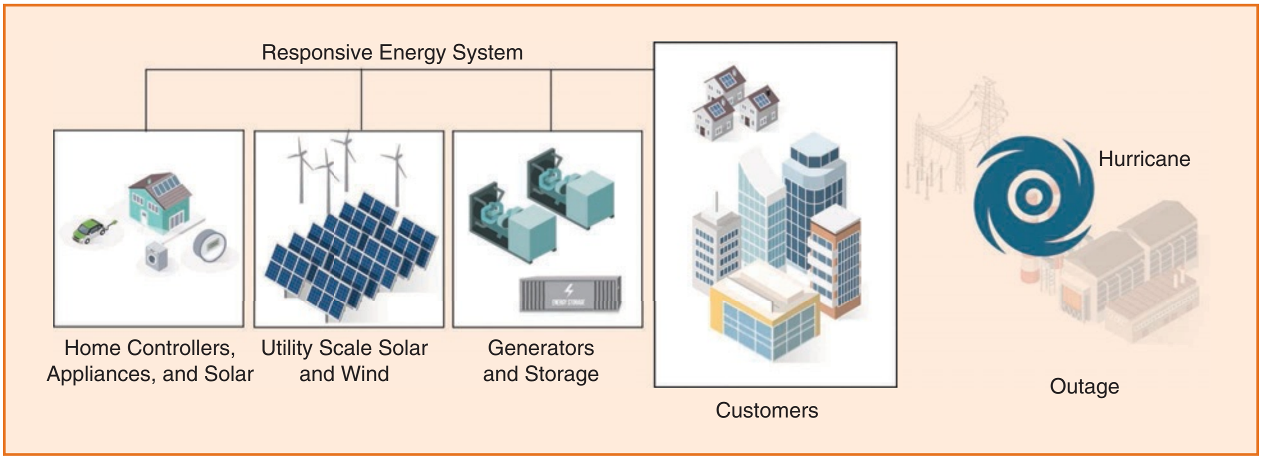

figure 2. The combined power of dispersed DERs at all scales can restore power to customers and the larger grid quickly.

black-start functionality. New control technology allows inverter-based resources to synchronize dynamically and autonomously with no losses to the grid stability. Research and industry recognize the grid-forming capability provided by inverters in steady states and during system dynamics. Advanced controls, such as frequency regulation and voltage regulation, have been demonstrated and are widely available from inverter-based resources. Transient functions, such as fault current contribution and inrush current management, have been discussed and developed in some pilot projects. All and all, inverter-based resources are ready to take on the system restoration task on their own.

Let's again take the example of the imaginary grid hit by the hurricane. If the storm took out major transmission lines and transformers, the grid would likely black out entirely, and repairing it would take considerable time. If, however, a sufficient number of DERs remained functional after the hurricane and some distribution lines still connected users, these DERs could be used to power the community through smart control and protection schemes. Multiple communities that were powered quickly through these distributed technologies could amass enough energy to restore nearby thermal generators or provide a reduced cold-load pickup to speed up the grid restoration process.

Final Remarks

Power grid resiliency remains a critical focus for the modern grid system because of our dependence on electrical power in all sectors of the economy. With diversified energy resources, controllable devices, and other supportive technologies, we will have opportunities to rethink resiliency practices and continue to make them more robust and flexible.

For Further Reading

Y. Wang, C. Chen, J. Wang, and R. Baldick, "Research on resilience of power systems under natural disasters: A review," *IEEE Trans. Power Syst.*, vol. 31, no. 2, pp. 1604–1613, 2017. doi: 10.1109/TPWRS.2015.2429656. [Online]. Available: https://ieeexplore.ieee.org/document/7105972

K. Anderson, N. DiOrio, D. Cutler, B. Butt, and A. Richards, "Increasing resiliency through renewable energy microgrids," *J. Energy Manag.*, vol. 2, no. 2, pp. 22–38, 2017. [Online]. Available: https://www.nrel.gov/docs/fy17osti/69034.pdf

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society news *(continued from p. 88)*

- Publications chair, IEEE PES Energy Management and Power Delivery (EMPD) conference, Singapore (1995)
- Organizing chair, IEEE PES EMPD conference, Singapore (1998)
- Vice chair, IEEE PES Winter Meeting, Singapore (2000)
- Honorary secretary, International Power Engineering Conference (IPEC) (technically cosponsored by PES), Singapore (1997, 1999, 2001, and 2003)
- Chair, IEEE PES PowerCon, Singapore (2004)
- Chair, IPEC, Singapore (2005 and 2007)
- Chair, Probabilistic Methods Applied to Power Systems Conference (technically cosponsored by PES), Singapore (2010)
- Cochair, Asian Conference on Energy, Power and Transportation Electrification (ACEPT) (technically cosponsored by three IEEE societies), (2016, 2017, and 2018)
- Advisor, IEEE PES ISGT Asia conference, Singapore (2018).

Awards

- IEEE PES Singapore Chapter Outstanding Engineer Award (2000)
- IEEE PES Outstanding Power Engineering Educator Award (2009)
- IEEE Singapore Section Outstanding Volunteer Award (2013)
- Distinguished Lecturer, IEEE PES.

Statement

As a volunteer with IEEE and PES for more than 30 years, I have served in various capacities, including Singapore Section Chair, and Regional Representative for Asia-Pacific Region 10. The power and energy industry is going through a transformational phase with renewables and their integration, energy storage, and digital technologies, and so on, and PES needs to stay at the forefront for members' benefit. I will endeavor to bring value to both younger and experienced engineers at the technical and educational levels—in particular, we need to continue to attract younger and diverse members for a sustainable future for the Society. If elected, I will also continue my predecessors' great work to curtail costs and keep the budget in check to benefit the volunteers. I will help build close relationships with IEEE sister Societies, develop good relations with other professional associations, and build global outreach for the benefit of IEEE members. My experience in attracting and promoting talent, identifying and nurturing innovation, and managing budgets, will be highly beneficial for this IEEE Board of Directors position.

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Yingchen "YC" Zhang and Juan Torres

safeguarding the grid

diverse resources for resilience

FROM WILDFIRES, HURRICANES, and floods to cyberattacks, the grid is vulnerable to natural and human-made disasters, which can cause widespread outages that last from hours to months and leave lasting economic impacts. Imagine a coastal region in the United States that has just been hit by a hurricane and lost all power. Besides the electricity infrastructure going out, communications networks, rail transportation, and gasoline pumps may also stop working after the emergency event, which often delays repair efforts to the grid. Unresponsive communications make it difficult to dispatch workers to repair the grid, and missing transportation links delay shipments of replacement equipment for the grid's restoration.

On the other hand, imagine a modernized grid that has just been hit by the same hurricane. This grid has smart controllers, storage, distributed generators, and demand response, which work together to significantly reduce the length of a power outage and decrease the restoration time of the full grid. Designing a responsive energy system is the solution to improving the grid's resilience and minimizing the damaging effects from storms, cybersecurity disruptions, and other threats. Enhancing grid resilience is a two-step process: 1) hardening the grid to mitigate the effects of widespread disasters and 2) quickly restoring the grid to minimize downtime following emergencies.

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Hardening the Grid With Diversified Resources

Conventional grid-hardening investments have focused more on creating stronger physical components that can withstand significant natural disaster impact from events such as hurricanes. Examples of hardening the grid can include utilities moving overhead lines underground to reduce impact, building barriers and walls around substations to curtail flooding, and reinforcing the physical mounting of towers. Weighing the cost of grid-hardening investments against the benefits of a more resilient electric infrastructure is always a delicate task.

Utilities are increasingly using nonwire alternatives (NWAs) to diversify the cost of upgrading infrastructure for normal operations. These alternatives can include storage, load management, microgrids, and distribution generation. Although NWAs will not directly prevent the infrastructure from being destroyed by a disaster, because these increasingly diversified technologies help the grid become much flexible and reconfigurable, power grids can now sustain the impact from natural disasters more effectively.

Marshaling Advanced Forecasting Technologies and Smart Controllers

One NWA technology for hardening the grid is forecasting. Advancements in data analytics methods, especially artificial intelligence, enable short- and long-term forecasts to be more accurate. Recent developments in these forecasting techniques can quantify uncertainties and assist grid operators with accurately allocating and scheduling resources to maintain normal grid operations. Meanwhile, this enhanced forecasting technology becomes a powerful tool to reduce the effects of natural disasters on power systems as well as assess the risk and quantify the impact of component failures. Forecasting technology can also identify resource availability, organize system configuration, and schedule resources to plan an accurate restoration path with fast response measures.

Smart controllers are another NWA that can keep the grid operational during an emergency event. Flexible alternating current transmission systems controllers, smart switches, and other controllers make it possible to reroute the power supply to customers, even while part of the bulk grid is still out of service. The expertise provided by forecasting combined with advanced controllers reduces the investment cost of grid hardening and is flexible for a large variety of utility scenarios.

Mobilizing Distributed-Energy Technologies

Research has also shown that instead of purely relying on traditional power networks to maintain resilience, the demand side should become more flexible. For instance, a resilient community with predictive household

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