Smart Grid...
Putting it All Together
...a 2010 reprint journal from PES
The IEEE Transactions on Smart Grid is intended to be a cross disciplinary and internationally archival journal aimed at disseminating the results of research on smart grid that relates to energy generation, transmission, distribution and delivery. The journal will publish original research on theories, technologies, design, policies, and implementation of smart grid. The Transactions will welcome manuscripts on design, implementation and evaluation of energy systems that include smart grid technologies and applications. Surveys of existing work on smart grid may also be considered for publication when they propose a challenging perspective on the future of such technologies and systems. The initial topical issues considered by the Transactions include:

- Smart sensing, communication and control in energy systems
- Wireless communications and advanced metering infrastructure
- Smart grid for energy management in buildings and home automation
- Phasor measurement unit applications for smart grid
- Smart grid for plug-in vehicles and low-carbon transportation alternatives
- Smart grid for cyber and physical security systems
- Smart grid for distributed energy resources
- Smart grid for energy savings and financial management
- Smart grid in interdependent energy infrastructures
- Smart grid for intelligent monitoring and outage management

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Smart Grid...
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TO: Recipients of this IEEE PES Smart Grid Special Publication:

Greetings from the IEEE Power and Energy Society (PES)!

THE ENCLOSED ARTICLES WERE all published in PES’s Power & Energy Magazine during 2009. We have re-packaged them into this special issue so that we could provide a handy reference on various perspectives on Smart Grid. For those of us in the power industry, we know that our grid has been “smart” for a long time. We have been working on standards and technology for many years that allow the grid to operate at the high levels of security and reliability that we enjoy today. But the grid will definitely get smarter in the future, and begin to deliver a lot of the benefits and efficiencies that have only been talked about for the last several years.

Smart grid means many things to different audiences. It has been nearly impossible to gain a consensus on a precise definition of smart grid, and I will not attempt to do so here. Some companies are already well along the path towards a smarter grid, while others are just beginning. But hopefully after you read these articles, you will have a better appreciation for what smart grid is….as well as what it is not!

One thing is clear—Smart Grid encompasses a lot more than just the “Grid”. It encompasses topics such as how to integrate renewable energy sources and energy storage devices into the existing power grid, and doing so with no compromises in reliability. Smart grid requires a high level of cyber-security to keep it safe from intrusion by unauthorized persons. From a customer perspective, a “smart” grid will be expected to integrate supply to new applications such as electric vehicles in a seamless manner. In addition, utilities may need to develop special rate structures to accommodate the charging cycles for electric vehicles during off-peak periods. And let’s not forget that Smart Grid is much more than just a bunch of technology topics. We must also consider policy development and regulatory impacts. And while we’re at it, we have to consider the impacts on economics, society, and the environment. You will note that we have tried to cover many of these perspectives on Smart Grid at a very high level. Here’s a quick rundown of what you can expect to gain from reading the enclosed articles:

✔ What is the “Grid of the Future”, and are we ready for it?
✔ Why phasor measurements are so important to real-time monitoring on a Smart Grid
✔ Why security is so critical to the Smart Grid
✔ Why Energy Storage Technologies are critical to the integration of Renewables into Wholesale Markets
✔ What Wind Power is and is not—a dose of reality for your consideration
✔ How large-scale Solar Power can be accommodated on a Smart Grid.

The Power & Energy Society is working hard with other IEEE societies to pull together all of the existing standards that will govern smart grid, as well as to develop those that do not exist. If you are not an IEEE and PES member, we invite you to join us as we pursue this challenging and exciting effort. You’ll not only gain the ability to stay up to date with the latest developments in the technology and standards from the world’s leading and most respected source, but you’ll also gain the ability to add your voice to the effort. In addition, if you’re ready to learn more about Smart Grid, we invite you to log onto the IEEE Smart Grid Web Portal at the following link: (http://smartgrid.ieee.org/). This site is intended to be your key web page for everything about Smart Grid. We recommend you save it as a “favorite” and return often to check progress.

With Warmest Regards,

Alan C. Rotz
IEEE PES President
Are We Ready to Transition to a Smart Grid?

MANY BELIEVE THE ELECTRIC POWER SYSTEM IS UNDERGOING A PROFOUND change driven by a number of needs. There’s the need for environmental compliance and energy conservation. We need better grid reliability while dealing with an aging infrastructure. And we need improved operational efficiencies and customer service. The changes that are happening are particularly significant for the electricity distribution grid, where “blind” and manual operations, along with the electromechanical components, will need to be transformed into a “smart grid.” This transformation will be necessary to meet environmental targets, to accommodate a greater emphasis on demand response (DR), and to support plug-in hybrid electric vehicles (PHEVs) as well as distributed generation and storage capabilities.

It is safe to say that these needs and changes present the power industry with the biggest challenge it has ever faced. On one hand, the transition to a smart grid has to be evolutionary to keep the lights on; on the other hand, the issues surrounding the smart grid are significant enough to demand major changes in power systems operating philosophy.

Business and Regulatory Drivers for the Smart Grid
With emerging requirements for renewable portfolio standards (RPS), limits on greenhouse gases (GHG), and DR and energy conservation measures, environmental issues have moved to the forefront of the utility business. The RPS mechanism generally places an obligation on electricity supply companies to provide a minimum percentage of their electricity from approved renewable energy sources. According to the U.S. Environmental Protection Agency, as of August 2008, 32 states plus the District of Columbia had established RPS targets. Together, these states account for almost half of the electricity sales in the United States. The RPS targets currently range from a low of 2% to a high of 25% of electricity generation, with California leading the pact that requires 20% of the energy supply come from renewable resources by 2010 and 33% by 2020. According to a Congressional Research Service report, RPS non-compliance penalties imposed by states range from $10 to $55 per megawatt-hour.

by Ali Ipakchi and Farrokh Albuyeh
Regional initiatives to cap greenhouse gases are also being formalized in the West, and in the Northeast, carbon dioxide cap-and-trade capability has been rolled out. Compliance with these environmental policies will require significant changes in utility operations and considerably greater degrees of information management and control.

Many state regulatory commissions have initiated proceedings or adopted policies for the implementation of advanced metering infrastructures (AMI) to enable DR. In its ruling on October 17, 2008, the Federal Energy Regulatory Commission (FERC) established a policy aimed at eliminating barriers to the participation of DR in the organized power markets (independent service operators (ISOs) and regional transmission organizations (RTOs)) by ensuring the comparable treatment of resources. In this ruling, FERC states: “Demand response can provide competitive pressure to reduce wholesale power prices; increases awareness of energy usage; provides for more efficient operation of markets; mitigates market power; enhances reliability; and in combination with certain new technologies, can support the use of renewable energy resources, distributed generation, and advanced metering. Thus, enabling demand-side resources, as well as supply-side resources, improves the economic operation of electric power markets by aligning prices more closely with the value customers place on electric power.” Among other things, the order directs RTOs and ISOs to accept bids from DR resources for energy and ancillary services, eliminate penalties for taking less energy than scheduled, and permit aggregators to bid DR on behalf of retail customers.

The reliable supply of electric power is a critical element of our economy. The new operating strategies for environmental compliance, when combined with our aging transmission and distribution infrastructure, challenge the security, reliability, and quality of the electric power supply. When implemented throughout the system, intermittent energy resources, such as wind, will greatly stress transmission grid operation. The distribution grid will be stressed with the introduction and, perhaps, rapid adaptation of on-site solar generation as well as PHEVs and plug-in electric vehicles (PEVs). Plug-in vehicles could significantly increase the
circuit loading if the charging times and schedules are not properly managed and controlled. Grid management issues would be exacerbated further if the car batteries were used as generation resources to provide energy and ancillary services into the grid. Major upgrades to the distribution system infrastructure may be required to address bidirectional flow patterns and increased loading. But the existing power delivery infrastructure has significant room for improvement through automation and information management, condition monitoring, and asset management, especially on the distribution system.

**Challenges with Large Penetration of Intermittent Resources**

Wind has been the fastest growing segment of the renewable industry. Solar generation is lagging behind, but new advances in technology show great promise for solar generation, which could catch up to and even overtake wind generation. New wind or solar power generation facilities can be installed, interconnected, and commissioned in a relatively short time frame, provided that the grid can handle the new capacity. The economics of these resources are fast improving, reaching a close parity with fossil generation. Figure 1 shows a comparison of capital costs for new generation using various technologies.

Over the past two decades, wind technology has improved significantly with turbines as large as 6 MW and costs below $2 million per megawatt of installed capacity; large wind farms with several hundred megawatt capacities are being deployed over several months.

Within the next few years, new solar photovoltaic (PV) manufacturing facilities in many regions of the country promise to add enough capacity to produce thousands of megawatts of solar cells and modules per year. New technologies, such as depositing solar modules onto a flexible plastic substrate or using solar “inks” (e.g., copper indium gallium selenide) and a “printing” process to produce thin film solar panels, are poised to drastically reduce the cost of solar power plants to less than $1 per watt.

Solar power plants can be built where they are most needed in the grid because siting PV arrays is usually much easier than siting a conventional power plant. Furthermore, unlike conventional power plants, modular PV plants can be expanded incrementally as demand increases. It is anticipated that municipal solar power plants with few megawatt capacity built close to load centers will become common during the next decade.

However, these intermittent renewable resources pose many challenges for the grid and grid operators:

- **Transmission system issues:** Good sites for wind or large-scale solar plants (greater than 100 MW) may be located in areas distant from any existing transmission lines or areas with limited available transmission capacity. These capacity limits are the most fundamental constraint facing wind power project developers, since it can take many years to plan and build new transmission infrastructure. Planning for transmission expansion to support increasing levels of wind generation in dispersed areas is essential to the growth of the wind sector.

  Planning and system stability studies are needed to determine seasonal requirements for “up regulation” and “down regulation” (seconds) and ramping (minutes) capacities. It should be pointed out that significantly higher levels of regulation and ramping capacity might not be readily available in regions with a thermal and nuclear generation base. Long-term resource adequacy issues also need to be addressed.

- **Distribution system issues:** The increasing penetration of residential and municipal solar generation imposes challenges on the existing distribution infrastructure and the system operator. New flow patterns may require changes to the protection and control strategies, enhanced distribution automation and microgrid

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**Figure 1.** New generation cost comparison.
capabilities, voltage and var management, and overall enforcement of distribution grid infrastructure.

✔ Interconnection standards: The interconnection standards may have to be further unified and broadened to address greater levels of power factor control and low-voltage ride through (LVRT) needed to mitigate any transient stability issues.

✔ Operational issues: The intermittent nature of the wind and solar generation poses certain operational challenges for the transmission grid, including additional ramping and regulation requirements and impacts on system stability. For example, due to the steepness of the wind turbine power curve (as shown in Figure 2), a wind farm creates significant ramping needs as wind speed changes, with the wind farm typically operating at either low output or high output at any given time. At high wind speeds, the turbine controls cut off the power generation to prevent damage to the blades and the turbine-generator assembly due to overspeed and possible tensional oscillation. This power cutoff poses additional operational challenges due to a very steep reduction in generation levels.

✔ Forecasting and scheduling: The RPS targets in many regions of the United States make wind and solar generation a must-take resource, thus eliminating any incentives for the wind or solar farm operator to provide balancing energy or install storage capacity. The limited dispatchability and intermittent nature of wind and solar generation require grid operators to supply the additional ancillary services (e.g., spinning reserves and regulation) needed to maintain reliability and operational requirements. For example, according to the California Independent System Operator (CAISO), an additional 350 MW of regulation and 800 MW of ramping capacity will be needed to support the planned 9,000 MW of new wind generation capacity. The large penetration of wind generation may also lead to overgeneration conditions.

Accurate hourly and subhourly wind and solar generation forecasting is needed to allow for other unit commitment and ancillary service provision as well as the scheduling and dispatch of the required hourly ramping and load following. Regional scheduling practices for intermittent resources need to be further enhanced to address banking and shaping in addition to energy balancing needs.

Energy storage, DR, distributed resource management, and the dispatch of wind and solar resources could partially alleviate some of these challenges.

Impact of Plug-in Hybrid Electric Vehicles on the Distribution Grid

PHEVs show great promise; they have the potential to curb emissions and reduce the cost of transportation. Although wide-scale adoption of plug-in vehicles is still a few years away, politicians, electric utilities, and auto companies are eagerly awaiting the opportunities that may arise from reduced emissions and gasoline consumption, new services and increased revenues, and new markets that would create new jobs. This is particularly true for electric utility companies, which could see substantial revenue growth through the electrification of the transportation market segment. For consumers, plug-in vehicles will significantly lower operational costs when compared with traditional gasoline cars or today’s gasoline-electric hybrids. The savings are potentially huge, as electricity costs per mile work out to about one-quarter to one-third the cost of gasoline, depending on the region and price of gasoline.

A Pacific Northwest National Laboratory (PNNL) study states that the existing generation, transmission, and distribution system in the United States, if optimally utilized at all hours of the day, could provide enough power for plug-in vehicles to replace up to 73% of the nation’s cars, vans, SUVs, or so-called

![figure 2. Wind turbine power curve.](image)
“light-duty fleet.” What’s more, switching from gas-only vehicles to mostly plug-in vehicles could reduce the importation of oil by up to 52%, according to the PNNL.

“Proper or optimal” use of the power grid, however, may not be as simple as it sounds. Plug-in vehicles will represent a significant new load on the existing primary and secondary distribution networks, with many of these circuits not having any spare capacity and no monitoring and automation capability. The additional charging load will typically be behind either an existing secondary distribution transformer in a residential neighborhood or a circuit/transformer connected to a distribution feeder. A charge for 30–40 miles of driving will require 7–10 kWh of power, since most plug-in vehicles require 0.2–0.3 kWh of charging power for a mile of driving. This will add significant load to the distribution network as the penetration level of PEVs increase.

Figure 3 provides a summary of some of the PHEV models that have been recently announced. They range in battery capacity from 16 kWh to 53 kWh. As can be seen, a full charge within a reasonable time—say, less than 3 to 4 hours—will require plugs with 6.6kW or 16 kW capacities.

Figure 4 illustrates a typical household load with a plug-in vehicle charging load of 1.4 kW in the evening. During its charging time, the plug-in vehicle more than doubles the average household load. Fast chargers, at 6.6 kW or higher, will significantly alter the load pattern of the consumer.

**Will We Face Distribution Circuit Congestion?**

The load of a customer or a group of customers on the distribution system constantly changes. Often, planners size and configure distribution equipment based on statistical load surveys and historical load profiles, while taking the load diversity into consideration. Data—such as average, maximum, and diversified demand; maximum noncoincident demand; load factor; and diversity factor—are used to design and configure

---

**Table: Plug-in Vehicle Charging Time**

<table>
<thead>
<tr>
<th>Type</th>
<th>Driving Range on Batteries (Miles)</th>
<th>Battery Energy kWh</th>
<th>Mile/kWh</th>
<th>Single-Phase</th>
<th>Three-Phase</th>
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<td>16</td>
<td>5</td>
<td>8</td>
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<tr>
<td>Compact</td>
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<tr>
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<td>220</td>
<td>53</td>
<td>5–7</td>
<td>33</td>
<td>12</td>
</tr>
</tbody>
</table>

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**Figure 3.** Plug-in vehicle charging time.

**Figure 4.** Typical residential home load profile in Southern California with superimposed PHEV charging load.
distribution circuits. Most distribution systems in the United States were designed decades ago based on the loading analysis performed at the time. Major changes in load levels and load patterns may require upgrades to the transformers and other equipment or changes to the switching configuration shifting loads between transformers. Furthermore, loading of a distribution feeder is inherently unbalanced because of the large number of unequal single-phase and double-phase loads that must be served. Unbalanced conditions, resulting from an increasing number of plug-in vehicles, could result in degradation of power quality, increased harmonics and voltage problems, and increasing line losses, and they also could potentially damage utility and customer equipment. In addition, significant changes in load patterns can impact line voltages, especially over long feeders.

On a typical distribution circuit, shown in Figure 5, most residential and commercial customers are served from radial feeders and secondary distribution networks. More than 80% of all distribution circuits within the United States are in the 15-kV class voltage level; the primary voltages are 12.47, 13.2, or 13.8 kV. The sizing of such circuits varies greatly; however, under typical operating conditions, 4–6 MVA is representative of the peak loads on most 15-kV class feeders. These circuits typically have a main three-phase feeder with various three-phase and single-phase lateral branches. Also typically, the larger commercial or industrial loads are served from the main feeder and metered at the primary voltage. For most other customers, the primary voltage is stepped down with distribution transformers to the “secondary” or low-voltage level, 480Y/277 volts or 208Y/120 volts for the three-phase voltages serving most commercial buildings and 240/120 volts for single-phase service, which serves most residential customers. Typical pole mount or overhead transformers are sized at 25 or 50 kVA for single-phase applications serving several single-family residences. Three-phase transformers are standardized at 75, 150, 300, or higher kVA levels.

**Figure 5.** A typical radial distribution feeder—potential circuit congestion conditions.
Several PHEVs or PEVs plugged into a secondary circuit, or a larger number of cars in a parking garage connected to a lateral feeder, could cause a localized overload on the distribution circuit and transformers. Many distribution circuits have been operating close to their operating limits, and the additional load may push them above their emergency operating limits. For example, a 25-kVA or 50-kVA secondary transformer on a single-phase lateral may not be able to sustain the charging loads of several plug-in vehicles while it’s subjected to variations in demand due to normal customer activities. Furthermore, the potential unbalanced conditions created by such loads could cause problems on main feeders and other laterals.

Shopping malls, big-box stores, and office buildings are considering offering fast charging capability to their customers and employees. This will result in significantly higher loading on the facility’s transformer. Figure 6 shows the additional loading caused by charging plug-in vehicle batteries as a function of the number of cars.

Such distribution circuit overload scenarios are conceptually similar to the congestion conditions on the transmission system due to excessive flows on a given transmission line. Changes in power flows on a distribution circuit have similar effects as changes in interchange flows on the transmission system.

Managing distribution system overloads may be akin to the congestion management in the transmission system that was addressed in the wake of opening the transmission system as a result of electric industry deregulation in the mid-1990s. This resulted in the need for transmission reservation and scheduling (the open access same-time information system (OASIS), interchange distribution calculator (IDC), and E-tagging) and the use of locational pricing to manage congestion. Perhaps similar concepts need to be considered for distribution capacity reservation and/or the use of locational retail pricing to manage the loading of the distribution facilities. Other concepts developed on the transmission system, e.g., firm and curtailable schedules, may also need to be extrapolated to the distribution system, or concepts like distribution loading relief (DLR), in contrast to transmission loading relief (TLR), may emerge. But most likely, these issues will be addressed through DR and distributed resource management strategies. In addition, mandating the use of time-of-use meters, coupled with improved rates and tariffs that would provide additional granularity and accurately reflect the cost of distribution system congestions at the point of sale, would encourage natural demand-side control and would promote proper scheduling of plug-in vehicle charging.

**Demand Response: Moving from a Load-Following to Load-Shaping Strategy**

Load management has been around since the early 1980s. Direct load control, peak shaving, peak shifting, and various voluntary load management programs have been implemented by many utilities with varying degrees of success. Now, with the push for energy conservation and demand-side management as a key strategy for environmental compliance, DR is taking on new realities. In addition to traditional load management, the advanced metering infrastructures (AMIs) being deployed by many utilities around the country will enable the implementation of targeted dynamic tariffs, management of demand-side energy resources, and integration of retail demand-side capabilities with wholesale energy markets. Many expect that dynamic and market-based rates will become the default retail tariff in many regions with AMI capability.

Initiatives, such as NIST/Gridwise Architecture Council efforts to define Home-to-Grid (H2G), Building-to-Grid (B2G), and Industry-to-Grid (I2G) interoperability requirements, as well as International Electrotechnical Commission (IEC) standards for home area networks (HANs), will enable the integration of demand-side resources with distribution and, in the aggregated form, with transmission operations. The end-use devices, such as intelligent appliances and smart chargers, will have visibility of possible distribution grid conditions (congestion) and dynamic prices, and they will be able to make local decisions to control their consumption. The system operator will be able to monitor and, either directly or through price signals, manage demand. The grid will be ready to move from the traditional load-following operating strategy to a load-shaping strategy, in which demand-side resources are managed to meet the available generation and the grid’s power delivery capabilities at any time.

FERC Order 719 directs ISOs and RTOs to remove some of the barriers to demand-side participation in the ancillary service markets. Yet, the information infrastructure needed to make this a reality is lacking. Furthermore, the existing rate structures and market tariffs will need to be modified to

![figure 6](image-url)
enable DR to reach its promised potential. Some ISOs and RTOs are taking the approach of treating DR simply as negative generation and imposing the existing tariffs and technology requirements on DR resources.

**Can Plug-in Vehicles Help in Load Shaping?**

Plug-in vehicles and other distributed resources will offer capabilities that can be used for shaping the distribution system load. As illustrated in Figure 7, car batteries, when treated in an aggregated fashion, represent a considerable level of distributed storage capability. Furthermore PHEV and PEV batteries are designed for fast discharge to provide for rapid car acceleration and other driving conditions that need a burst of power. Thus, parked PHEVs and PEVs with Vehicle-to-Grid (V2G) capability in a given area can alleviate localized distribution system overload problems. Moreover, if a group of parked cars with V2G capability are aggregated, they can provide ramping and regulation in support of the power grid. Ancillary services markets, on the other hand, are well-suited for batteries since spin and nonspin reserve markets require quick response times with low total energy demand. A recent demonstration project has successfully shown V2G capabilities supplying ancillary services, including real-time frequency regulation, in the PJM Interconnection market. The project successfully connected a plug-in vehicle with 19-kW V2G capability to PJM’s Automatic Generation Control (AGC) signal and demonstrated the battery’s ability to closely follow the regulation control signal for regulation-up and regulation-down requests. Frequency regulation, when compared with other market products, provides the highest market value at about $30 to $45/MW per hour; spinning reserve provides the second-highest value at $10/MW per hour. The primary revenue in both of these ancillary service markets is for capacity rather than energy. It should be pointed out, however, that the design of many of the early PHEVs and PEVs allows only for a one-way flow of charge, and excessive cycling of a plug-in car battery may drastically shorten the life of the battery.

**The Critical Role of Information and Automation Technologies**

A broad-based implementation of the smart grid will impact many of the existing utility operational and information systems, as shown in Figure 8. In addition to advanced metering and utilitywide communications infrastructure enabling DR and distributed resource management, the smart grid

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![Figure 7](image1.png)  
**Figure 7.** Distributed storage capacity of a fleet of plug-in vehicles.

![Figure 8](image2.png)  
**Figure 8.** A view of the utility information systems impacted by smart-grid strategies.
impacts many of the operational and enterprise information systems, including supervisory control and data acquisition (SCADA), feeder and substation automation, customer service systems, planning, engineering and field operations, grid operations, scheduling, and power marketing. The smart grid also impacts corporate enterprise systems for asset management, billing and accounting, and business management. Many expect that by between 2012 and 2014, there will be a significant number of plug-in vehicles and utility-grade solar generation on the distribution grid. As discussed earlier, this could result in system overloads, voltage/var deviations, and excessive phase imbalances. To mitigate these issues and to maintain system reliability, coordinated voltage and var control, automated switching and relay coordination, and extensive monitoring will be required. In addition, a combination of distributed intelligence and centralized analysis and control, congestion management strategies, and market-based dynamic pricing will be needed. As illustrated in Figure 9, many information technology (IT) systems will be impacted, including those for distribution management and automation, operations planning, scheduling and dispatch, market operations, and billing and settlements.

**Challenges with the Implementation of a Smart-Grid Information Technology System**

Currently, most utility companies have limited interoperability across the different systems for operations and business management. In most cases, the information in each organizational “silo” is not easily accessible to applications and users in other functional units. A smart-grid strategy requires information integration across these currently autonomous systems and business activities. It is important to provide a single, consistent view of information throughout the organization, making enterprise data accessible securely and in a timely fashion to users across the enterprise.

For most utilities operating in a regulated business environment, the implementation of an integrated smart-grid capability poses many challenges. Nonconventional or large capital projects usually require significant lead times, as illustrated in Figure 10. Even though

**Figure 9.** Systems required to support the high penetration of distributed resources.

**Figure 10.** A broad-based timeline for smart-grid IT implementation.
the project timeline can be shortened by conducting activities in parallel, there are other complicating factors. Some of the challenges associated with smart-grid projects include:

✔ Not having a clearly defined end state: The driving forces for the smart grid are a function of many external factors, including the economy, oil prices, and political and regulatory mandates. As a result, the requirements and the timing of the end state are not established well enough to allow the development of detailed technical and business specifications.

✔ The incremental and evolving nature of the applications: Many of the changing requirements are incremental with respect to the existing capabilities. “Forklift” replacement of the existing systems to add these incremental capabilities might not be an economical and operationally acceptable option.

✔ The many legacy business functions and systems they touch: Smart-grid functions touch many existing operational systems and business processes. As such, an implementation plan endorsed by all stakeholders will be required.

✔ A rollout with minimum impact on existing operations: The reliable supply of electric power cannot be disrupted, and incremental additions should not have any negative impact on the existing and unaffected operations.

✔ The required data interfaces with external and third-party systems: The smart grid requires interfaces with external users and systems, including smart devices, customers, service providers, and energy markets. Cybersecurity and integration issues need to be addressed.

✔ A lack of standards and established business practices: Many of the smart-grid applications are new, with limited technical standards and no established industry business practices.

✔ The high cost of implementation: The business cases for smart-grid initiatives should be made based on

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**Figure 11.** Using the cloud for smart-grid applications.
operational and societal benefits. The regulatory framework for rate-based smart-grid projects needs to be further strengthened.

Meeting the Smart-Grid Information Technology Challenge: Leveraging the Cloud

One of the emerging and, perhaps, game-changing developments in the IT industry has been the use of the Web (the cloud) as the computing and information management platform. This will allow the integration of data and capabilities from multiple, diverse sources to deliver powerful composite applications over the Web. These applications are hosted in data centers that offer extensible computing capabilities to provide the scalability and security needed for many of the emerging new applications—without a major impact on the legacy systems behind the utility enterprise firewall. This will also minimize the need for additional internal IT resources.

Using this model, new smart-grid applications can be easily implemented to augment the existing utility capabilities. The model also provides the flexibility needed to add new capabilities as the requirements arise. Figure 11 provides a conceptual illustration of this model, in which the Web is used as a platform for the incremental addition of new smart-grid applications and their integration with utility legacy systems and external systems and users.

A cloud-based smart-grid strategy can address many of the challenges stated above.

✔ It provides a cost-effective approach for an incremental or phased rollout of functionality as needs arise, without the need for forklift replacement of the legacy systems.

✔ It provides the capability for securely integrating the new capabilities with existing internal and external systems, and connecting those to users and customers.

✔ It provides a framework for the easy integration of third-party and partner capabilities.

✔ It allows the new capabilities to be implemented in parallel with the existing operations and systems, while minimizing the impact on the ongoing operations.

✔ It leverages the software as a service (SaaS) model, minimizing capital outlays and project implementation time.

Web services, service-oriented architecture (SOA), and event-driven architecture (EDA) are integral elements of cloud computing. They provide a wealth of proven capabilities for systems integration. Efforts are under way to define standardized services for the power application integration, e.g., IEC 61970 for energy management systems and the common information model (CIM). Other standards also exist, such as IEC TC57’s IEC 61850 for substation automation; IEC 61968 for distribution management systems; and IEEE standards, American National Standards Institute (ANSI) standards, and other regional and utility standards for network design, distributed generation interconnections, and operations. Even though these standards provide some framework, they are not fully adopted and supported across the industry.

Concluding Remarks

The traditional model—large remote power stations with central dispatch, long transmission lines, and a distribution system primarily designed to deliver power from transmission substations to load centers with established load profiles—may be evolving into a new approach. This new approach will accommodate greater levels of demand-side management; generation and storage resources on the distribution system; generation closer to the loads; perhaps greater flexibility for islanding and micro-grids; and considerably higher levels of intermittent generation, especially on the transmission system. These changes not only may require changes to the power system capacity and capabilities, but they also will have a significant impact on the IT needed to monitor and control the reliable operation of the power system in a most economical fashion. The IT impact is particularly significant for the distribution grid, where, traditionally, very limited sensors, automation, and information are available. These IT capabilities are the key to the smart grid.

For Further Reading


Biographies

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EVERYDAY LIFE RELIES HEAVILY ON THE reliable operation and intelligent management of critical infrastructures, such as electric power systems, telecommunication networks, and water distribution networks. Designing, monitoring, and controlling such systems is becoming increasingly more challenging as a consequence of the steady growth of their size, complexity, level of uncertainty, unpredictable behavior, and interactions. These critical infrastructures are susceptible to natural disasters, frequent failures, and malicious attacks. At the epicenter of the well-being and prosperity of society lie the electric power systems. The secure and reliable operation of modern power systems is an increasingly challenging task due to the ever-increasing demand for electricity, the growing number of interconnections, penetration of variable renewable energy sources, and deregulated energy market conditions. Power companies in different parts of the world are therefore feeling the need for a real-time wide area monitoring, protection, and control (WAMPAC) system. Synchronized measurement technology (SMT) has the potential of becoming the backbone of this system. The major advantages of using SMT are that 1) the measurements from widely dispersed locations can
be synchronized with respect to a global positioning system (GPS) clock, 2) voltage phase angles can be measured directly, which was so far technically infeasible, and 3) the accuracy and speed of energy management system (EMS) applications (e.g., state estimation) increases manifold.

At present, phasor measurement units (PMUs) are the most widely used SMT-based device for power system applications. The first prototype of the PMU was developed and tested in Virginia Tech in the early 1980s. The first commercial unit, the Macrobryde 1690 was developed in 1991. In the late 1990s, Bonneville Power Administration (BPA) developed a wide area measurement system (WAMS), which initiated the usage of PMUs for large-scale power systems. Figure 1 shows the block diagram of the PMU, originally developed at Virginia Tech. PMU technology is maturing rapidly, and a number of vendors are offering equipment either with phasor measurement facilities alone (standalone PMUs) or with additional protective relaying features (integrated PMUs). Various compliance levels and performance metrics for PMUs are prescribed in the IEEE standard C37.118-2005 for synchrophasors for power systems. A PMU, when placed at a bus, can provide a highly accurate measurement of the voltage phasor at that bus, as well as the current phasors through the incident transmission lines (depending on the available measurement channels). Modern PMUs have some other features, like frequency measurement, measurement of derived quantities (e.g., power components, power quality related indicators, etc.), and monitoring of the status of substation apparatus.

**Figure 1. Basic architecture of a PMU.**

**SMT Deployment in Different Parts of the World**

PMUs are increasingly being used in different parts of the world as the major technology enabler of the WAMPAC system. The general objective of these PMU installation activities is to eventually make a transition from the conventional supervisory control and data acquisition (SCADA)-based measurement system to a more advanced measurement system that will utilize synchronized measurements from geographically distant locations and increase the situational awareness by monitoring a wide area of the power system in real time. This will help in observing the dynamics of the system and taking necessary protection and control actions in real time. In various countries, PMUs or relays with PMU capabilities are being installed on a test basis by academic or utility researchers to perform case studies, measurements, and analyses of the capabilities of synchronized measurement devices. These devices are typically installed on adjacent buses and usually their measurements are not used by the system operator. However, synchronized measurement devices are being deployed in certain parts of the world and used in applications such as system monitoring, post disturbance analysis, monitoring of interarea oscillations, and system modeling. A brief overview of the existing PMU deployment in some of the major world economies is presented next. As the list of applications is dynamic as more and more PMU devices are being deployed, the list below is not exhaustive. Table 1 summarizes the major PMU-related activities in different parts of the world.

**Table 1. PMU deployment in different parts of the world.**

<table>
<thead>
<tr>
<th>PMU Applications</th>
<th>North America</th>
<th>Europe</th>
<th>China</th>
<th>India</th>
<th>Brazil</th>
<th>Russia</th>
</tr>
</thead>
<tbody>
<tr>
<td>Post-disturbance analysis</td>
<td>P</td>
<td>P</td>
<td></td>
<td>T</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Stability monitoring</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Thermal overload monitoring</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Power system restoration</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Model validation</td>
<td>P</td>
<td>T</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>State estimation</td>
<td>T</td>
<td>T</td>
<td>T</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Real-time control</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Adaptive protection</td>
<td>T</td>
<td>T</td>
<td>T</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
<tr>
<td>Wide area stabilizer</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
<td>P</td>
</tr>
</tbody>
</table>

T = Testing phase; P = Planning stage

**North America**

More than 200 PMUs are installed and more are in the pipeline under the North American Synchrophasor Initiative (NASPI). A number of utilities in the United States, Canada, and Mexico are involved in this project. The short-term (one to three years) goal of this project involves angle/frequency monitoring, post-mortem analysis, voltage stability monitoring, thermal overload monitoring, improved state estimation, steady-state model benchmarking, applications related to distributed generation, and power system restoration. The medium-term (three to five years) goal involves the use of SMT for congestion management, dynamic model
benchmarking, and planned power system separation. The long-term (beyond five years) objective of the project is to use SMT for state estimation (using PMU measurements only), real-time control, adaptive protection, and implementation of wide area power system stabilizers. Innovative techniques for real-time data analysis and utilization of PMU measurements for better monitoring of stability of the system are being developed in the participating organizations.

**Europe**
A number of WAMSs are in operation in Central and Western Europe. The utilities in the Nordic countries are already using PMUs extensively. Countries in Central Europe have started using PMUs and are currently exchanging synchronized measurements for better monitoring of the system. At present, the synchronized data are mainly used for post-disturbance analysis and improved system modeling. However, the major focus is on developing systematic ways for monitoring and damping of interarea oscillations, such as the feedback control of high-voltage dc (HVDC) links or static var compensators (SVCs), by using the PMU measurements. Additional benefits of using SMT, such as angle and voltage stability monitoring, line thermal monitoring, and online parameter estimation are included in the near-term goal.

**China**
A well-developed measurement system comprised of several WAMSs is already in place in China. The Chinese standard on PMUs and WAMS was issued by the State Grid Company and manufacturers in 2005. More than 700 PMUs are already in operation. According to the 11th five-year plan of the power grid, all 500-kV substations and 300-MW and above power plants in the Chinese power grid will install PMUs within the next five years. Major applications that are currently in use are the real-time visualization of the system dynamics and transmission capacity, wide area data recording and playback, and monitoring of interarea low frequency oscillations. Work is in progress to include further applications such as enhanced state estimation, online security assessment, adaptive protection, and emergency control.

**India**
In India, the central transmission utility, Powergrid, is planning to install 20–25 PMUs at critical buses in different regional grids. The synchronized measurements from these PMUs will be used for model validations and the development of a common state estimator combining the regional state estimators. Based on the success of this stage, more PMUs will be installed to explore different advantages of SMT and develop remedial action schemes (RASs) and system integrity protection schemes (SIPSs).

**Brazil**
The Brazilian independent system operator started two WAMS-related projects in 2000, aiming at the recording of wide-area disturbances and applying synchronized measurements for improved monitoring and control of the system. The preliminary study regarding the compliance and feasibility of integrating SMT-based devices into the existing measurement system, and the design of the integrated system architecture have been completed. A number of pilot projects for testing and validating SMT applications are in progress.

**Russia**
More than 25 PMUs are in operation in the synchronously interconnected power system of 14 countries including Eastern Europe, Russia, Central Asia, and Siberia. The major application areas currently being served are the system performance monitoring, model validation, and monitoring of interarea oscillations. A procedure for dynamic model validation is developed, based on the measurements associated with a disturbance. Pilot projects are in operation for developing real-time control methodologies using synchronized measurements.

**SMT Applications**
The continuing research on SMT reveals innovative applications in an increasing number of power system areas. The following list gives an overview of some of the important areas where significant improvement can be achieved by utilizing synchronized measurement technology:

- real-time visualization of power systems
- design of an advanced warning system
- analysis of the causes of a total or partial blackout
- benchmarking, validation, and fine-tuning of system models
- enhancement in state estimation
- real-time congestion management
- real-time angular and voltage stability analysis and enhancement
- improved damping of interarea oscillations
- design of an adaptive protection system.
We will describe the recent developments in some of these important applications.

**WAMS Implementation for Wide Area Backup Protection**

Relay protection has always played an important role in safeguarding the secure operation of modern power systems. The performance of relay protection is evaluated by indices such as selectivity, sensitivity, reliability and interoperability. However, with the ongoing trend towards deregulation and interconnection of power systems, the traditional relay protection cannot keep pace with the demands of bulk power systems.

According to statistic data, relays are involved in one way or another in 75% of major disturbances (for more information the reader is referred to Phadke and Thorp in “For Further Reading”). One of the most important reasons is that the existing protections only utilize the local data and try to eliminate the faulted element or mal-operating condition as soon as possible without considering the impact of such an action on the whole system. If a network is already stressed, the unexpected occurrence of flow transferring might drive the system into cascading trips as some backup protection might lose their selectivity. Furthermore, the step principle for time setting of relay zones achieves selectivity at the sacrifice of rapidity; the inborn time delay characteristic in clearing faulted lines might also undermine the stability and security of the power system. The investigations of blackouts in power systems around the world indicate that although the protective relays operated according to the pre-defined logic, the system status was deteriorated and finally collapsed.

The advent of WAMSs provides a platform for synchronous data acquisition, exchange and analysis, as the snapshot of the whole system can be updated every 20–50 ms. These features open a new path for enhancing the performance of power system protection, especially backup protection, since the time delay of backup protection makes it possible to acquire and deal with the synchronous data of power systems. It should be pointed out that, at the current stage of understanding in the field of SMT, the philosophy of the main protection should not be changed with the advent of WAMS. On one hand, acquisition of phasor measurements will inevitably increase the time delay of the trip signal, having an adverse impact to system stability. On the other hand, the introduction of WAMS information makes the main protection more complex, which might affect the reliability negatively. It can be concluded that WAMS-based backup protection integrated with local data-based main protection may be a promising methodology to protect bulk power systems against blackouts. Research work is being undertaken in this area.

**WAMS-Based Flow Transferring Identification Algorithm**

To handle the cascading trip problem caused by the unexpected occurrence of flow transferring in the power grids, the fundamental solution is to monitor the load and try to identify whether the overload is caused by flow transferring or an internal fault. If flow transferring does occur in the system, then the backup relay should be blocked before the thermal limits are exceeded, and enough time should be allowed for the system to take remedial measures to eliminate the overload.

By introducing wide area information into backup protection design, a novel wide area backup protection and control scheme to prevent cascading trips can be designed, based on Kirchhoff’s circuit law and linear circuit theory. By comparing the online measured post-fault flow with the estimated post-fault flow distribution, through this scheme, it can be readily determined whether the overload of the branches
The benefits of SMT compared to the conventional measurement technology are too obvious to ignore.

was caused by flow transferring, by comparing the online measured post-fault flow with the estimated post-fault flow distribution.

A new concept of flow transferring relativity factor (FTRF) is defined as a linear proportion coefficient in the transferring equivalent network to estimate the flow distribution after flow transferring occurs. Because FTRF is only determined by the topology and parameters of the network, FTRF can be calculated before the fault. Once the network topology is changed, which can be identified online by the breaker open/close status, the current FTRF matrix can be recalculated rapidly by amending the previous FTRF matrix.

To mitigate the overload caused by flow transferring, an equal-quantum generator tripping and load shedding control strategy can be also achieved based on the concept of the network correlation coefficient. The whole scheme integrates the online measurements of WAMS and can guarantee simultaneously minimum control cost and eradication of cascading trips.

**Architecture of a WAMS-Based Wide Area Backup Protection Scheme**

A practical WAMS-based wide area backup protection system has been developed based on a real power system, utilizing the wide area time synchronization capability and fast transmission speed of WAMS. This system adopts a centralized architecture and consists of four substations (including a PMU measurement substation and a control substation), a communications network (2M fiber green) and one main station. The schematic diagram of the WAMS-based wide area backup protection system is shown in Figure 2.

The main station and the substations are connected through the distributed network. The main station performs

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**Figure 3.** Multimachine test power system.
two main functions: the first is to collect, monitor, manage, and maintain the real-time synchronized phasor data and real-time switching information uploaded from the PMU measurement substations; the second is to diagnose wide area faults, judge protection logic, and issue control orders (such as tripping or blocking) to the control substations. The substation completes two major tasks: one is to sample, convert, and upload the real-time data; the other is to execute control orders received from the main station. The PMU measurement substation synchronizes the real-time phasor data and real-time switching information with a synchronized time-stamp and forwards synchronized data to the main station.

The function of the control substation is to realize the protection logic through an Ethernet network. The function of the storage server is to store and forward the historical data, and the function of the display server is to inquire historical data and monitor the real-time power system operating status.

Synchronized phasor measurement technology is becoming mature; WAMS has been widely established in modern power grids and is becoming one of the most important data sources of dispatching centers. The large disturbances that occurred in recent years demonstrate the powerfulness of WAMS in the areas of dynamic monitoring and system modeling as well as parameter validation. However, the issue of how to integrate phasor data to develop advanced applications to reduce the probability of occurrence of blackouts is still an open one.

**Monitoring of Power System Oscillations**

Real-time monitoring and identification of the characteristics of interarea oscillations, including damping factors and frequency of oscillations, is a prerequisite for applying corrective measures for system stabilization in large power systems. A wide area measurement approach based on the use of synchronized measurement technology leads to more efficient damping of interarea oscillations as well as the prediction of instabilities which might cause cascading outages and, potentially, large-scale blackouts.

The eigenvalue analysis is a traditional method for offline analysis of dynamic properties of power systems. It is based on the assumed system model and the classical methods of linear systems control theory. With the help of eigenvalues, eigenvectors, and participation factors, the system characteristics can be predicted. However, this hardly meets the severe requirements for efficient monitoring of dynamically changed power systems possessing a high level of uncertainty. The system topology and state are dynamically changed. The system parameters are not constant. Renewable energy resources are introducing additional challenges due to their variable nature. All the above issues affect the suitability of the traditional eigenvalue analysis approach for determining the dynamic properties of modern power systems.
In the last two decades, a number of solutions for online monitoring and identification of power system oscillation modes were presented in the scientific literature. After detecting interarea oscillations (e.g., by using methods based on wavelet transform), damping and frequency components are commonly determined by applying methods based on the fast Fourier transform based techniques, or approaches based on different parameter estimation methods. The Prony method is one of the frequently used parameter estimators, capable of determining the unknown damping and frequency of the system oscillations. Using this method, oscillations can be analyzed by processing various signals available through wide area measurements: local system frequency, speed of generators, and instantaneous active power through an intertie transmission line.

According to the dynamic properties of power systems and the range of low frequency oscillations, the oscillation modes are classified as local and interarea modes. The local modes may be associated with the internal speed oscillations of a single generator against the rest of the power system, which is similar to the behavior of a single-machine infinite bus system. In a multimachine power system, the oscillations between two groups of generators are described through the interarea oscillation modes. The 22-bus test power system with ten generators shown in Figure 3 is used to demonstrate the interarea oscillation modes. From the topology of the test power system, two areas, A and B, connected over two parallel intertie lines can be noted. Under steady-state conditions, a 500-MW active power is transferred over the intertie line from area A to the area B.

The classical eigenvalue analysis method is compared with the results obtained by using the Prony method. Based on the eigenvalue analysis, the dominant interarea oscillation modes and are shown in Table 2 (note that there are 131 oscillation modes in the multimachine system of Figure 3).

To apply the Prony method for determining the unknown damping and oscillation of the dominant interarea oscillations, a single line-to-ground fault at one of the two parallel intertie lines, starting at s and lasting for 100 ms is simulated. The fault provoked severe oscillations at all interconnected generators (see Figure 4, in which the instantaneous rotor speeds of all generators are presented). The oscillations between two coherent groups of generators (groups A and B) are obvious.

For this temporary short circuit, the active power flow (see Figure 5) over the sound intertie line from Figure 3 was used as an input to the Prony method. In Table 3, the unknown frequency and damping of the dominant oscillation

<table>
<thead>
<tr>
<th>Results</th>
<th>Dominant Oscillation Damping</th>
<th>Dominant Oscillation Frequency (Hz)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Eigenvalue analysis</td>
<td>0.23923</td>
<td>0.99378</td>
</tr>
<tr>
<td>Approximate results by Prony method (mean value from sliding windows)</td>
<td>0.23816</td>
<td>0.99417</td>
</tr>
<tr>
<td>Relative errors (%)</td>
<td>0.447</td>
<td>0.04</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Technique</th>
<th>Advantages</th>
<th>Disadvantages</th>
</tr>
</thead>
<tbody>
<tr>
<td>Integer programming</td>
<td>Less computational time, applicable for systems of any size</td>
<td>Existence of local minima, not all constraints can be expressed in simple mathematical form</td>
</tr>
<tr>
<td>Evolutionary techniques, such as genetic algorithm, simulated annealing, particle swarm optimization</td>
<td>Elimination of the problem of local minima, virtually any type of constraints can be incorporated</td>
<td>Large computational time, free parameters of the algorithms need to be tuned carefully to get the optimal solution</td>
</tr>
</tbody>
</table>
Synchronized measurement technology has the potential of becoming the backbone of a real-time wide area monitoring, protection, and control system.

mode, estimated from the processed active power, are presented. For comparison reasons, in the same table, the results obtained from eigenvalue analysis are also presented. It is obvious that the Prony method delivered practically useful results, which provides the operator with the information that the oscillations are damped. Furthermore, the estimated damping and frequency of the dominant mode can be forwarded to the power system stabilizer (PSS) to control the damping of the oscillations. The use of wide area information of damping could lead to more efficient stabilization of slow oscillations in the system.

The results obtained by using the Prony method correspond to the results obtained over the classical eigenvalue analysis. Based on the results, it is possible to design an efficient early instability predictor. The functionality of such a predictor would be based on the analysis of the value of the damping estimated over the Prony method. For a negative damping, an alarm signal should be issued and the operator should be warned to initialize a corrective action to prevent the instability.

**Challenges**

SMT is a relatively new technology and has received significant attention from power system researchers in recent years. At present, the industry practice is to install PMUs in an incremental fashion in conjunction with conventional measurements such as power flow and power injection. As the cost of PMUs is reducing, they will be used in greater numbers, probably to achieve full system observability based on PMUs or improvement in the state estimator performance. However, conventional measurements will continue to be used in parallel to the PMUs, enhancing the robustness of state estimation and ensuring system observability in the case of device or component outages. The techniques to find the optimal location of PMUs in a power system both in the presence and in the absence of conventional measurements should therefore be available to the system planners. The existing approaches to the problem of optimal PMU placement are summarized in Table 4. The issues such as measurement redundancy and uncertainty should also be considered while placing the PMUs. In the presence of conventional measurements, one important criterion for PMU placement is the improvement of existing state estimator performance. For example, a frequently encountered problem in state estimation is the large value of the condition number of the gain matrix. (The condition number is a measure of how ill-conditioned a gain matrix is, i.e., a measure of sensitivity to numerical operations. A large condition number indicates that we may not be able to trust the results of computations for that gain matrix.) The PMU placement can be done in such a way that the condition number of the gain matrix is reduced when PMU measurements are combined with conventional measurements.

As the number of installed SMT-based devices in a power system increases, the communication network will be increasingly congested. Two approaches exist to cope with this challenge: increasing the communication bandwidth and reducing the volume of transmitted data by using data compression techniques and/or transmission of only the important data. One or both of these approaches along with proper data management protocols will help in alleviating the congestion of communication channels, increasing the security of the data against possible disturbances or malicious attacks, and reducing the latency in the transmitted information (thereby helping in the realization of the wide area control system). Several options exist for high-speed wide area communications, including frame relay, switched multimegabit data service (SMDS), digital subscriber line (DSL), asynchronous transfer mode (ATM), and synchronous optical network (SONET).

Another challenging area is the integration of synchronized measurements with the conventional measurements. A state estimation method such as the least-squares error (LSE) estimator should be used to estimate the states of the power system based on the measurements obtained from the PMUs. In the presence of conventional measurements, such as the asynchronous remote terminal unit (RTU)-SCADA measurements, the nonlinear LSE estimator is in use. This is the consequence of the fact that the network model is nonlinear. The nonlinearities are caused by the unknown phase angles, which are considered as unknown model parameters to be estimated. It is known that nonlinear estimators require essentially more computational time compared to linear ones. In addition, the convergence properties of nonlinear estimators are not as sophisticated as in the case of linear estimators. In the case that only synchronized measurements are used, the estimator will be linear; however, such a case is still far away. In fact, the nonlinearity of the state estimator is a sweet price to be paid for the enhanced robustness provided by the larger redundancy of combined SCADA/PMU measurements. The PMU measurements can be synchronized with the conventional measurements by using the time stamps. To determine the best time at which the PMU data is to be used with other measurements requires...
extensive system-specific case studies. An interesting area of investigation is the use of high-fidelity synchronized data to detect, identify, and process bad data in the conventional measurements.

PMUs offer highly accurate measurements of voltage and current phasors and frequency when operating under steady-state conditions and nominal frequency. Significant error creeps into the measurements, however, while operating under transient conditions or off-nominal frequencies. The amount of measurement error varies from one manufacturer to another due to the difference in the algorithm used to compute the output quantities. This poses a serious question to the SMT’s ability to monitor dynamics of a power system at the time of disturbances. The current version of IEEE Standard C37.118 for synchrophasors specifies the acceptable limit on the total vector error (TVE) of synchronized measurements under such conditions. More detailed compliance criteria need to be developed to harvest maximum benefit of the SMT for monitoring, protection and control of a power system under all operating conditions.

Roadmap for SMT Penetration into the Power Industry

The power industries need to develop a clearly defined roadmap for adopting SMT. This roadmap should include both short-term objectives such as enhanced visualization of the power system, post-disturbance analysis, and model validations, and long-term objectives such as the development of a wide area monitoring, protection and control system. In a major part of the world, PMU deployment is in the initial stage, involving the evaluation of pilot projects experimenting with the operational capabilities of PMUs. A number of areas that need to be addressed while planning and designing for wide-scale deployment of PMUs are the following:

- **Compatibility**: A thorough investigation needs to be carried out to examine the compatibility of SMT-based devices with the existing measurement system. The availability of the required bandwidth and communication facilities is a prerequisite for PMU deployment. To simplify this problem, some manufacturers are coming up with software-only upgrade facilities, i.e., PMU capability can be added to the existing relays and meters with a software upgrade, without requiring any hardware changes.

- **Optimal placement**: The usual practice is to install PMUs in an incremental fashion in conjunction with the existing measurement devices. A number of criteria should be kept in mind while determining the optimal PMU locations such as the observability of the system, the strategic importance of the load or generator buses, and the possibility of future expansion.

- **Flexibility**: The design of the system architecture involving PMUs should be flexible enough to accommodate new measurement devices and additional measurement load from any future expansion in the system.

- **Protocols**: Standard network protocols need to be developed for handling the synchronized devices and associated measurements, and storage and usage of the measured data. This will help in seamless integration of new devices from different manufacturers into the existing system and easy handling of the measurement data from different locations.

SMT is a relatively new technology and still in the development stage. This article presented a brief account of the existing practices in some of the major world economies, the major challenges to the integration of SMT into the existing power systems, and highlighted some of the major innovative application areas. However, the benefits of SMT compared to the conventional measurement technology are too obvious to ignore. Significant research activities are taking place in different parts of the world for the development of methodologies and techniques for the large-scale deployment of PMUs in power systems.

For Further Reading


Biographies

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For more than a century, we have accepted the premise that once electricity is produced, it cannot be stored. This lack of storage causes extreme electricity price volatility (compared with other commodities) and hourly fluctuations in wholesale market prices, and has prompted specialized real-time markets that provide price fluctuations in 5- or 10-min intervals. The hourly volatility reflects the widely disparate costs of production from different resources that lead to a steep supply curve in most markets; that steep supply curve, coupled with highly variable demand and an inelastic demand curve in today’s markets, makes for high volatility.

Ancillary Services, Roles, and Impacts
To ensure the constant balance of production and demand, the electric industry has developed a number of “ancillary services” market products that generators sell to market operators. One of these services is frequency regulation. Regulation is a service that provides for second-by-second variation in output to match instantaneous demand and maintain system frequency and “control area” flows to other areas within tolerance. The typical North American market operator [such as the PJM Interconnection or the California independent system operator (ISO)] normally procures a regulating power bandwidth from the generators on the order of 0.5–1% of peak load. Generators that provide this service have to hold that capacity out of energy production to accommodate the fluctuating control signals, and thus incur an opportunity cost for lost production as well as some additional wear and tear on their equipment. Recent studies also indicate that small efficiency degradation and moderate to severe emissions degradation are imposed on some units.

Spinning reserve is another important ancillary service. The grid operator needs enough extra generation capacity on line (thus spinning) that can respond quickly to a major system disturbance,
such as the loss of a generator. Control areas typically carry as much spinning reserve as does the largest single generator on line (which is usually the largest nuclear or coal-fired power plant). Spinning reserve represents another significant opportunity cost for the generators that provide it, and the hourly price for spinning reserve, as with regulation energy, is often closely correlated with hourly energy prices.

Real-time dispatch or balancing energy is also an important market product. In a market environment, this specialized market in “increments and decrements” is cleared every 5 or 10 min. In a vertically integrated environment, this economic dispatch is more effectively continuous and more tightly integrated with regulation. In the market environment, the balancing phenomenon is accentuated since the various generators have hourly schedules established in hour-ahead and day-ahead markets. These schedules are artificially “flat” during the hour, and the balancing energy is required to match production to demand continuously.

Hourly scheduling is performed by unit commitment or security-constrained unit commitment in both regulated and deregulated market environments. The goal is to match “scheduled” generation to “forecast” load on an hourly basis.

Traditional power generation equipment (hydroelectric, steam or gas turbine, diesel/gas internal combustion) has speed governors to keep the unit rotational speed or frequency matched to the nominal system frequency. Normally, the grid regulation signals keep system frequency within a tight tolerance of the nominal frequency so that governors are not engaged for system frequency response. However, after a major disturbance, such as the loss of a large power plant, the governors will be actuated. The extent to which each plant’s governor acts is coordinated within the control area, and plant operators are required to set governor droop or sensitivities accordingly.

As previously noted, the current paradigm of a steeply differentiated supply curve and an inelastic demand curve makes for high variations from peak to off-peak prices. Peak prices reflect not only the variable cost of production of the most inefficient units, but also the need of the owners of those units to recover fixed costs during a few hours of production in a year. Because the peak clearing prices affect the whole (unhedged portion) market, they have become a lightning rod for stakeholders unhappy with deregulated wholesale markets.

This leads to increasing efforts to develop demand response as a resource in the wholesale markets; in effect, the market operator pays consumers not to use energy at peak hours. Demand response aggregators enlist consumers in programs to get energy consumption under control and then “bid” that response into the wholesale markets. This mechanism works well today for the relatively small percentage of commercial and industrial consumers that participate. Yet, if future system economics were to require greatly increased demand response utilization, it is unclear how well residential consumers would take to frequent curtailments. Demand response alone is not a panacea for structural changes in the electric supply system that might aggravate peak prices or increase the need for ancillary services.

**Impact of Variable Renewables on Wholesale Markets**

Renewable resources—wind and solar—are more variable as a result of weather than are traditional energy resources. Wind and solar both have diurnal effects that vary geographically. Mountainous regions, coastal areas, and plains all exhibit different patterns of wind velocity and wind farm production. Storms, too, can affect production: Most wind turbines are feathered and shut down at very high wind velocities. Solar is, of course, inherently diurnal, and in some coastal regions, solar may be affected by diurnal fog and cloud effects.

The best commercial wind forecasts have a standard deviation of as much as 15–30% depending on the time frame during which the measurement is made. Matching renewable supply to demand becomes more difficult when the variability of wind and solar output is taken into account. Studies have shown that the amount of regulation, balancing energy, and spinning reserve required in the markets may increase significantly. Depending on the study and the market considered, varying amounts of increases are expected based on existing state renewable portfolio standards (RPS) policies. Figure 1 shows the key results of a number of studies done for U.S. control areas in recent years. Typically, additional regulation is required due to the minute-by-minute variability of renewables production. Additional balancing energy is required due to the potential for large deviations from the forecast. Additional spinning reserve is potentially required if the loss of production from a particular wind farm geography is greater than the largest fossil unit on the system—a condition expected to exist in many regions.

Many renewable resources are or will be remote from load centers and located where limited transmission capacity exists today. This is an intensely discussed issue that factors into the American Recovery and Reinvestment Act of 2009. Less discussed is the amount of transmission capacity that is economically appropriate for a given renewable capacity. Given the low capacity factors of renewable resources, does it make sense to build transmission capacity to the peak capacity of the renewable resource? Absent storage, it is inevitable that the peak capacity of remote generation and the average capacity factor of transmission will be mismatched.

**The Role Storage Can Play**

Storage can provide ancillary services and “free up” generation capacity to provide energy. Storage is demonstrably capable of providing governor response, regulation, and spinning reserve. Today, pilot programs are under way in several markets to demonstrate the effectiveness of storage for regulation service.
Regulation has been the first target of the merchant storage community because, today, open markets exist and the nature of regulation as a “zero energy” delivery service is well suited to low-duration, fast storage technologies, such as flywheels and lithium-ion batteries.

The key question for the merchant storage operator is: What duration is required of these devices? This question relates to which individual market requirements are needed for the regulation service provider to maintain an incremental or decremental output level for a period of time. North American Electric Reliability Council (NERC) standards do not explicitly require the area control error (ACE) to maintain a zero average value during any particular time period, so, in practice, the sizing of storage duration in a particular market is a judgment call.

Spinning reserve can also be provided by storage. In most markets, the duration requirement is formally 1 h, which can make storage too expensive today. However, some market operators are beginning to ask whether there is a need for a new reserve product that could be met with shorter durations. A potential advantage of storage is that it could provide locational reserves in places where new traditional generation cannot be sited (urban locations).

In many markets today, the balancing energy volumes (and therefore prices) exhibit a spiking behavior in opposite directions immediately before and after hourly schedule transitions. Storage devices can be used to balance the ramping transitions economically. In today’s world, a storage device can effectively arbitrage the balancing price variations profitably.

Larger-scale storage, with durations of several hours or more, can play an important role in conjunction with wind farm operations when transmission capacity is limited. Storage can capture wind energy production at peak outputs for farm operations when transmission capacity is limited. Storage as a Provider of Regulation Services

The first published work analyzing the benefits of fast storage for regulation was performed by KEMA for Beacon Power. The study involved an economic analysis of the revenues available to a flywheel storage facility and also examined the emissions impacts of shifting regulation away from conventional units. A summary of the results of the study is shown in Figure 2. The study demonstrated that fast storage could be economically viable for regulation services. In addition, the impact of regulation services on fossil plant emissions could be reduced systemwide.

The next step in evaluating fast storage for regulation services was also performed by KEMA, this time for The AES Corporation. This study (an IEEE Power Systems...
Renewable resources—wind and solar—are more variable as a result of weather than are traditional energy resources.

Conference & Exposition (PSCE) paper) utilized a dynamic simulation of the real-time markets, system operations, and generation resources to investigate the performance of lithium-ion batteries for regulation services in several markets. An overview of the model is shown in Figure 3. The study established several important points. First, it showed that under existing regulation protocols, a duration of an hour or less was sufficient for regulation services. Second, it established that the overall economics of regulation revenues—net balancing energy revenues and payments, including electrical losses in the battery system—were favorable. Third, it demonstrated that a new “fast regulation service” concept could be a win-win for system operators and storage operators. A summary of the results of the study is shown in Figure 4, where the charts show the performance of fast-response batteries in specific ISO territories. A fast regulation service that used fast storage preferentially for regulation (over participating fossil units) and also acted to maintain average storage energy levels at a target level would provide improved system ACE performance while imposing lesser regulation duty on the fossil units. The entries highlighted in yellow are cases in which the storage capacity was insufficient some amount of the time. In the tables shown in Figure 4, the term “AGC [automatic generation control] Control” applies to simulations that were run in which the storage units were used in the same way as any generator providing regulation, sharing in the regulation service with other fossil units on the same basis. The “Filtered ACE” data refers to a scheme in which the filtered ACE signal was sent preferentially to storage units and the output of those units was subtracted from the AGC signal remaining for the fossil units. In this way, whenever the storage units could satisfy AGC needs completely, the fossil units would not be moved at all.

Since the study, at least two market operators have begun work on protocols for regulation services to be provided by storage. Typically, the filtered ACE is the control signal. Both of these operators recognize the need to maintain storage target energy levels. However, the additional step of using storage as the primary regulation resource is not yet in development—perhaps because it will not be realistic until storage becomes a significant share (30% or more) of the regulation resource.

Spinning reserve prices tend to follow energy prices: At peak price periods, the opportunity cost of providing spinning reserve approximates the peak price of energy less the fuel cost of generation. If the units needed to provide reserves are not economic, which can happen off-peak as well as
locationally, the market operator must pay a “reliability must run” price to keep the units on line for reserves. Storage can provide reserves based largely on a capital recovery charge. As storage costs drop below US$1,000/MW, this application becomes attractive. Since reserves are used infrequently, the application also suits storage technologies that exhibit degradation with charge-discharge cycles. In today’s markets, spinning reserve providers typically have to supply the energy for an hour when called upon. This adds to the capital outlay for a storage device, and if a spinning reserve service with a shorter duration can be used, then lower-duration storage devices can be applied at a lower cost and, therefore, price to the market.

**Ramping Issues with Wind Production**

Another serious issue is that wind production ramps up and ramps down (“falls off”) fairly rapidly at times. When this happens, other resources must adapt quickly. Today, the ramping requirements on the system overall are driven by the rate of change of the load during morning pickup and evening drop-off. This amounts to 0.5%/min, more or less. If wind capacity is 30% of the system and the wind can fall off in a 15-min time frame, the rate of change would amount to 2%/min—quite an increase over ramping driven by load. Maintaining this ramping capability with conventional units will have implications for scheduling and, ultimately, reserve requirements. One proposed solution is to “manage” the wind ramping by rate limiting the increase in wind production and ramping wind production down in a controlled fashion in anticipation of a wind falloff. This approach might be technically workable, but will result in lost wind energy. Storage offers a way to manage the rate of wind ramping with reduced energy production loss.

**Benefits of Storage with Wind Farms in Transmission-Constrained Areas**

With regard to storage applications, few areas have been given as much attention as the subject of combining storage

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**figure 4.** Performance summary of fast-response storage devices in specific ISO markets.
with wind farms. Typically, when storage is utilized in this application, the main goal is to help the wind operator control ramping issues associated with the variable nature of the wind farm output. However, storage is also used with wind for dealing with the transmission capacity issues associated with wind farms.

Figure 5 shows a typical wind farm power duration curve. Wind farms rarely operate at peak output. This characteristic makes it uneconomic to build transmission capacity to the peak power capacity of wind farms; however, if transmission capacity is built to a number lower than the peak, it can lead to congestion when wind production exceeds the transmission capacity. In other words, wind developers may find it economical to build wind capacity even though they know that congestion may develop and exist for a period of time.

Storage has the potential to mitigate such occurrences. The concept is much more than simple arbitrage applications since it focuses on energy that would otherwise be “lost” to end-users. When wind production exceeds the transmission system capacity or congestions occur on the system, storage can capture the “lost” energy and then discharge back to the grid when the congestion eases. The basic idea is to use storage to increase the effective capacity of the wind farm.

Figure 6 shows a graphical representation of the proposed solution. The red line shows the unconstrained wind farm output, or “potential capacity factor,” assuming that transmission capacity was built to wind peak. The blue line shows the “actual capacity factor” as the hypothetical transmission constraint limits the output. The green line shows an “effective capacity factor” that can be achieved through the use of storage.

**Economics of Storage with Transmission-Limited Wind Farms**

The economics of wind farm storage applications are driven by a few key factors. If you had unlimited storage capacity, the effective capacity factor would equal the potential full capacity factor of the wind farm. However, cost, size, and other factors compel wind developers to find a balance between the maximum (unconstrained) and minimum (take no action) capacity factors.

The economics of the application depend on the wind farm power duration curve, the transmission congestion duration curve, and the ratio of the storage capacity to wind farm capacity (both in terms of power and duration). Figure 7 shows typical nomograms of these results in terms of the energy harvested.

**Diurnal Patterns of Renewable Resources and Storage for Time Shifting**

Though wind has the potential to offer large amounts of renewable generation to the U.S. electricity grid, it is simply not a constant resource. In many geographies across the
United States, wind velocities follow regular diurnal patterns—meaning wind doesn’t blow consistently throughout the day, but rather reaches peaks at specific and typically predictable times and ebbs in the same manner. In mountainous regions, wind velocity might be greatest in the early morning and late afternoon/early evening and lowest during the daytime or in the middle of the night. In the plains, on the other hand, wind velocity might be greatest at nighttime. Offshore wind is typically more reliable; still, the pattern throughout the day varies.

Although emerging storage technologies are making great progress, the megawatt capacity needed to shift the potential generation of wind farms tends to outsize the capabilities of the storage technologies. There are really two main technologies that have the capacity to perform in this application: pumped hydro and compressed air energy storage (CAES).

The relatively low efficiencies and low cost of pumped hydro are more than compensated by the ability to avoid expensive peaking power. Where available, pumped hydro applications are an excellent resource to solve the diurnal problems; however, today, there are limited siting possibilities for new pumped hydro resources. An alternative to the problem can be found in a CAES system, diagrammed in Figure 8.

The Electric Power Research Institute (EPRI) has been developing the CAES concept for some years, and a number of pilot installations exist or are being planned. Technically, CAES is not a pure storage system since natural gas is added to the compressed air going through the turbine to boost power production and overall efficiency. Without this injection, the overall efficiencies of the cycle would also be low—around 70% to 80%.

CAES has the potential to be very large scale when underground storage is used. The first commercial CAES was a 290-MW unit built in Huntorf, Germany, in 1978. The second commercial CAES was a 110-MW unit built in McIntosh, Alabama, in 1991. The third commercial CAES, the largest ever, will be a 2,700-MW plant that is planned for construction in Norton, Ohio. This nine-unit plant will compress air to 1,500 lbf/in² in an existing limestone mine some 2,200 ft underground. Since the systems use conventional technology, installation costs are relatively low. The capital cost is predicted to be less than $1,000/kW, according to the Electricity Storage Association’s Web site.

CAES systems require conveniently located underground reservoirs. However, EPRI is also advancing innovative smaller-scale, aboveground systems that can be used at wind farm sites if natural gas is available. A particularly attractive idea is to deploy large-scale storage in a location that is close to both offshore wind and large urban load centers—where the net effect is to reduce transmission congestion during the daytime even if the renewable resource is peaking in the nighttime.

**Regulatory Issues and Emerging Technologies**

As the number of “utility-scale” storage applications begins to increase, regulatory issues are required to keep pace with the advancements. The number of potential storage applications that are being conceptualized exacerbates this challenge. It is easy to understand the reasons for the difficulty facing regulators. The electricity industry is one of the only remaining industries in which storage is not an integral part of the process. Though the industry has had pumped hydro systems, traditional lead-acid batteries, and the potential of CAES systems, it is only recently that a number of emerging technologies have entered the commercial marketplace. These advanced technologies are offering cycling capabilities in the thousands, mobility, and very fast response rates. The “modularity” of the technologies also ensures flexibility in the places where the technologies can be used (in distributed as well as large, stationary systems). As utilities, developers, and grid operators come to understand the unique characteristics of all the storage technologies entering the marketplace, more and more potential applications are being envisioned for the devices.

Hence, storage poses a regulatory puzzle: How do you keep pace with the advancements, and how do you even classify the technology to fit traditional electricity industry roles?
Some applications are clearly merchant applications, such as systems deployed solely for the purpose of providing ancillary services in markets. Companies such as Beacon Power (flywheels) and The AES Corporation are pioneering these applications. Other applications will almost certainly be regulated transmission or distribution assets. A hypothetical example of a regulated transmission asset could be a high-speed/capacity device installed locally in a distributed capacity so as to provide stability augmentation and increase transfer limits. A storage system in a distribution substation placed to shave peak loadings and defer capital expenditure is likely a regulated distribution asset or expense.

Other storage applications create “typical” debates between regulated and unregulated investors. A “community” storage device deployed at secondary voltage serving one to ten homes, for instance, could be considered a non-regulated backup power system or a regulated distribution asset, based (today) primarily on the way in which it is connected, protected, and controlled.

If a storage device is deployed in a substation at a wind farm in order to alleviate transmission congestion, is it a wind generation asset or a transmission asset? The regulatory treatment is obviously influenced by the ownership and control, but if two “investor types” disagree, the regulatory process will ultimately have to find an answer.

As storage applications begin to move beyond pilot applications and into full deployment, these sorts of issues are going to need to be addressed. Among all stakeholders and market participants, it is accepted that storage will play a role in the future electricity system. The American Recovery and Reinvestment Act has provided that storage is eligible for matching funds up to 30%. This acknowledgment of the devices may trigger a rethinking of the role of storage in the power system and most likely will force regulators to address the issues.

Storage on Islands with High Renewables
Storage at high capacities might have an especially compelling business case in island systems. Islands typically have good wind generation potential and usually have high electricity costs due to imported fossil fuel for generation (too often oil/diesel). Hence, there is high motivation to utilize renewables for generation: It would solve environmental issues related to fossil generation and allow areas to be marketed as environmentally friendly tourist destinations. In addition, because of the high energy costs, island storage applications tend to be economical for renewable power.

As such, several of the Hawaiian Islands, including Oahu, are contemplating 50% renewable levels in the not-too-distant future. At these levels, matching wind production (and solar production) to demand can be problematic even with very aggressive demand response systems. Large-scale storage offers a solution for both the demand matching and backup energy needs. The high penetration of renewable applications in small, closed systems will most likely serve to validate the predictions being made regarding the impact of a large penetration of renewable technologies. Since storage is currently being implemented for the renewable applications in Hawaii, the ability of storage to perform as envisioned and predicted also will be tested.

Hawaii has been examining how to increase renewable applications for a number of years. The process began with the Hawaii Clean Energy Initiative, a cooperative effort among the government of Hawaii; the Department of Energy (DOE); and partners that included representatives from industry, the public sector, and nongovernmental organizations. One of the key goals of the program was to examine integrating renewable energy—including solar, wind, energy storage, and advanced vehicle technologies—into existing systems to meet the islands’ energy needs. From private industry, members of the partnership included General Electric, UPC Wind (now First Wind), and Castle & Cooke. These players have been key drivers in advancing the renewable-storage concept.

In April 2008, the DOE’s National Renewable Energy Laboratory (NREL) signed a memorandum of understanding with First Wind’s Kaheawa wind farm on Maui. According to a NREL news release, the “Maui partner site will conduct research and development on advanced wind energy technologies, including operational and control studies, energy storage options and integration of renewable electricity into existing grids.”

Additional partnership activity has been occurring on the island of Lanai: On 7 January, 2009, Castle & Cooke officially kicked off its 1.2-MW solar farm. According to a news release from the office of Gov. Linda Lingle, “A partnership between Castle & Cooke Hawaii and SunPower Corporation, and built primarily by residents of Lanai, the La Ola Solar Farm is expected to supply up to 30% of the island’s peak electricity demand. The power will be purchased by Maui Electric Company (MECO) and transmitted to Lanai homes and businesses through MECO’s electric power grid.” Since the solar plant was predicted to reach penetration rates of 30% of peak, storage was considered essential to the application being approved for installation.

Future Directions
Over the last three years, in addition to emerging storage technologies entering the marketplace, various external factors have transformed the concept of storage into a tool that is generally accepted as a future component of the electricity grid.

✓ Interest in emission reductions: Storage can avoid the need for fossil generation to “levelize” renewable resource production.
✓ Acceleration of the penetration of plug-in hybrid electric vehicles (PHEVs) and electric vehicles (EVs): Storage can help support incremental peaking load (daytime parking) from PHEVs.
Accelerating the smart grid: As smart grids evolve from a speculative possibility to an expected future outcome, storage is also being considered a necessary tool for the future system. Storage offers a number of unique characteristics.

- Fast response (referring to the charging and discharging speeds of the devices): While traditional power plants, such as coal plants, have ramp rates measured in megawatts per minute, some of the technologies that make up the new category of “high-performance storage devices” have ramp rates rated in milliseconds.

- Cycles: The number of charging and discharging cycles of the storage devices is one of the main advantages gained by the technology improvements. Advanced batteries, such as lithium-ion, are currently claiming cycles in the range of 7,000–10,000. Flow batteries are claiming cycles in the range of 40,000. (Some manufacturers have claimed unlimited life.)

- Transportability: The advanced storage devices are transportable, which differentiates them from the large-scale storage applications, such as pumped hydro and CAES systems. The advanced batteries are packaged in the 500 kW to 2 MW range, are typically housed in the “tractor-trailer” type beds, and have the ability to be placed on any flat surface. They can be deployed for a year or two and then moved to a new location.

Today, storage technologies are being envisioned and piloted for applications in a range of areas.

- Ancillary services: This market is showing the greatest variety of interest for two main reasons: 1) Short-duration (15 to 30 min) devices are able to effectively serve the market, and 2) it is an active, competitive market that allows merchant storage operators to potentially profit from the application using short duration devices. This market is not the “capacity leader” in application, but it is currently seeing the most activity from a variety of storage devices, including flywheels, lithium-ion batteries, and flow batteries. As “loads as a resource” for ancillary services gains increasing attention, low-tech storage devices, such as thermal storage, are also beginning to be examined for application in this field.

- Renewable integration: Storage is being proposed and tested in combination with renewable systems. The main focus for storage in this area is with ramping issues of the solar or wind application to allow the developer to meet potential power purchase agreement requirements. This application also tends to require shorter-duration devices. However, with additional applications, such as energy arbitrage or congestion relief (discharging once grid congestion has dissipated), longer-duration devices (two to five hours) may be a better fit, as they will allow the operator to gain additional revenue for the application.

Ultimately, price will determine the degree to which storage technologies are deployed into the grid, but—as evidenced by the fact that the technologies are already being piloted for the aforementioned applications—some of the devices provide benefits that allow them to be successfully implemented even at today’s costs. As with all emerging technologies, it is difficult and sometimes fruitless to predict future prices, but as PHEVs and EVs enter the market, renewables deployment continues to increase, and current effective applications continue to be exploited, there will be sustained motivation to continue to improve storage technologies and lower the prices. At each stage of improvement, more and more applications will be envisioned and become economical. Every operating industry has some form of storage, except the electricity industry—and when that capability does become available, use of storage devices will only multiply.

For Further Reading


Biographies

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SUPPLYING ELECTRIC POWER REQUIRES a large and very visible electrical infrastructure made of transmission lines, substations, and generating plants. Today, however, these components cannot operate without the assistance of a much more concealed information infrastructure of communication links, instrumentation, and control centers. The massive expansion of this information infrastructure over the last three or four decades has delivered considerable economic benefits and reliability improvements. Most significant from an economic perspective is the ability to operate with smaller security margins because the operators have access to more and more accurate information about the state of the power system and means to rapidly respond to disturbances. Other important economic benefits
include the automation of substations and the ability to operate large interconnections. The information infrastructure also contributes to the security of the system by alerting the operators of undesirable events and by making quicker, more targeted corrective actions possible.

However, questions have been raised about the negative impact that this increasing reliance on the information infrastructure might have on the resilience of the power system. Reports on major incidents have mentioned malfunctions or inadequacies in the control and communication systems as contributing factors to the degradation of the situation that ultimately led to blackouts. There are also concerns about the impact that hacking or cyberattacks might have on the continuity of the electricity supply. It is therefore important and urgent to understand the mechanisms through which failures in the information infrastructure can endanger the security of the power system. Once these mechanisms are understood, we must quantify their potential impact. Finally, on the basis of this quantification we must then develop techniques to maintain or enhance the overall robustness of the system. The framework that is traditionally used to assess the security of power systems is not suitable for these tasks because it does not consider explicitly the information infrastructure. The main purpose of this article is thus to propose a new framework that clarifies the interactions between the primary “electrical” and the secondary “information” infrastructures in terms of security. Based on this framework, we will then outline a set of research issues and challenges that deserve the attention of the power system community.

What Does the Information Infrastructure Do?

Before addressing the security issues, it is probably worthwhile to review the various functions of what we have so far described as the “information infrastructure.” These functions can be broadly divided into two categories: monitoring and control. Monitoring encompasses all the functions designed to inform the operator about the state of the system. Some of these functions provide raw data such as the status of switching devices or measurements of voltages or power flows. Other functions process the raw data to provide higher-value information to the operator. For example changes in status are converted into classified and prioritized alarms. Similarly, the state estimation function transforms the raw measurements into a mathematically consistent representation of the state of the system. Further up the chain, the security analysis software uses the output of the state estimator to identify potentially dangerous situations and warn the operator about the need to take preventive action or to prepare for corrective action.

The other group of functions deals with the control of the system under both normal and abnormal conditions. Some of these functions are designed to operate automatically. Examples include protective relays that disconnect components when they detect the occurrence of a fault, the automatic generation control (AGC) system that adjusts the output of the generating units in response to changes in load, and system integrity protection schemes (SIPPS) that implement corrective actions when a stability-threatening situation is detected. Other control functions have been developed to assist operators in the implementation of corrective actions or to help them decide what control actions are required. The remote control of switching devices is a simple and well-established example. More complex control functions include rotating load shedding and the use of an optimal power flow program to decide how generation should be dispatched and transformer taps should be set to satisfy constraints on the operation of the transmission network.

It is worth noting that the implementation of all these monitoring and control functions relies on chains of hardware and software components and systems and some level of human intervention. For example, the security analysis function starts from measuring devices, progresses through communication links and the data acquisition subsystem of the control center, culminates in the network analysis software and terminates on the operator’s user interface. Except where redundancy has been incorporated in the design, the failure of any element of such a chain makes the function fail or degrades its performance.

A New Security Framework

A power system is considered secure if it is able to meet the demand for electrical energy of all consumers even when affected by a contingency. In practice, operators use simulation programs to check how the system would react if a fault were to cause the loss of any single transmission line, transformer, or generating unit. If the system is able to cope indefinitely with all these contingencies, no action is required. On the other hand, if any contingency makes continuing operation unstable or unsustainable, operators must redispach the generation and adjust the other control variables in a way that returns the system to a secure state in a timely fashion.
Questions have been raised about the negative impact that the information infrastructure might have on the resilience of the power system.

Figure 1 provides a simple illustration of this framework. We will consider that the power system is in the normal state if all electrical variables are within their acceptable range and if there is a sufficient security margin between the state of the system and its stability limits. On the other hand, we will deem the power system to be in an electrically abnormal state if either of the following conditions holds:
- the margin between the operating state of the system and its stability limit does not meet the security criteria
- some load has been disconnected (either involuntarily or voluntarily to prevent a collapse of the system).

Our definition of an electrically abnormal state therefore encompasses the alert, emergency, extremis, and restorative states of the classification of Fink and Carlsen (1978). However, for the purposes of this article, this subdivision is not necessary.

This traditional framework has served the industry and its customers well since it was developed in the 1970s. However, it suffers from two main limitations:
- It considers only faults and failures in the heavy current “electrical” infrastructure.
- It assumes that the information infrastructure provides the operator with a complete and accurate picture of the state of the system and with the adequate means to implement all necessary control actions.

To overcome these shortcomings, we propose to generalize this framework as shown in Figure 2.

For the power system to be in the normal state in this new framework, all the components of its information infrastructure must be operating normally. The power system enters the informationally abnormal state if any of its electronic components, including any part of its software, has stopped operating or has malfunctioned. A power system is in a combined abnormal state if its state is abnormal from both the electrical and the information points of view.

We now turn our attention to what can cause the system to move from a normal to an abnormal state. These transitions can be classified in four types as shown in Figure 2.

**Transitions of Type A**

Transitions from the normal state to the electrically abnormal state are quite familiar to power engineers and have been studied for a number of years. They can be triggered by any of the following events:

A.1) fault or failure of one or more electrical components
A.2) unexpectedly large or fast change in the load
A.3) failure by the operator to react in a timely manner to a change in system conditions.

Assuming that the information infrastructure is adequate and fully operational, transitions of type A are quickly detected by the monitoring and security assessment functions of the control center. Note that a further degradation of the operating state can take place within the electrically abnormal state due to cascading failures. On the other hand, not all faults and failures put the system in an electrically abnormal state. For example, when the system is lightly loaded and therefore not under stress, the tripping of a minor line will most often not trigger a violation of the security criteria. Returning the system to the normal state from the electrically abnormal state requires a redispatch of the generation or some other adjustment of the controls available to the operator.
Failures in the information infrastructure have been at least a significant contributing factor in several major recent incidents.

**Transitions of Type B**
The state of the system changes from being normal to being electronically abnormal when any of its electronic components stops operating properly or malfunctions. Examples of such transitions include the following:

- B.1) failure of any element in a measurement chain
- B.2) failure of any element in a remote control chain
- B.3) failure of a local control system (such as an automatic voltage regulator or speed governor)
- B.4) failure of a communication link between a station or substation and the control center
- B.5) failure of part or the whole computer system that the operators use to monitor and control the power system.

Most of these transitions will be caused by hardware failures, software failures due to programming bugs, or incorrect data. However, they could also be the result of cyber attacks on the control centers or on the distributed control and communication systems.

Some transitions of type B are easily detectable because the condition of many electronic components and subsystems is constantly monitored. For example, failures of communication links are usually reported to the operator using the same alarm system as events of an electrical nature. In addition, the redundancy that is designed in many information subsystems is such that not all failures instantly reduce the amount or quality of the information available to the operators or their ability to implement control actions. However, not all failures in the information infrastructure are easily detectable. For example, a protection relay may be inoperative or incorrectly set, but such a failure will remain hidden until the next time it is maintained or until this relay fails to react properly to an electrical fault.

Because of the complexity and size of the information infrastructure, it is probably impossible to demonstrate that all the electronic components are fully functional. Besides hidden failures in the protection system, there is always some probability that there are software bugs in the large amounts of computer codes used to monitor and control power systems. If these latent problems were taken into consideration, one could argue that the power system is always in an informationally abnormal state. Since this would confuse the issue, we will consider that the system shifts to an informationally abnormal state only when a failure manifests itself.

Restoring the system to the normal state from the informationally abnormal state requires the replacement or repair of failed hardware, a software reset or update, or a manual switchover to a backup system.

**Transitions of Type C**
These transitions represent the deterioration in the information infrastructure on top of a problem in the electrical state of the system. Such deterioration can happen in different ways:

- C.1) Some components of the information infrastructure stop functioning properly because their power supply has been interrupted or perturbed by the electrical problem.
- C.2) A fault reveals a hidden failure in a protection relay that may trigger the unnecessary disconnection of one or more other electrical components.
- C.3) The electrical disturbance that caused the transition from normal to electrically abnormal is so large that the number of alarms generated throughout the system overwhelms the alarm processing function at the control center.
- C.4) The electrical transition puts the electrical system in a state that is so close to the stability boundary that the state estimator or another application program that relies on a model of the power system fails to converge, depriving the operator of vital information.
- C.5) An unrelated failure happens in the information infrastructure after the electrical state has become abnormal.

Transitions of type C are dangerous because they reduce the operator’s ability to respond to the original electrical disturbance (C1, C3, C4, and possibly C5) or make the electrical situation itself worse off (C2). On the other hand, these problems have been identified for some time, and some corrective measures have been taken. For example, substations are equipped with emergency power supplies that are regularly checked (C1). The ability of alarm processing systems to cope with and prioritize the huge number of alarms generated by a major incident can be tested and improved (C3). Similarly, the robustness of state estimation and other power system analysis programs has been considerably enhanced in recent years. Hidden failures in the protection system (C2) remain a problem, and their impact on the probability of major incidents has been the object of a significant amount of research in recent years.

In some cases, the state of the system will revert from combined abnormal to electrically abnormal by itself. This is the case for transitions of type C2 because once a hidden
The classical framework for assessing the security of power systems assumes that the operator has a perfect picture of the state of this system.

failure in the protection system has been revealed, it cannot happen again (unless the same situation arises before the protection department has had a chance to identify and fix the hidden failure). This may also be the case for transitions of type C3. Transitions of type C4 can be reverted if the operator succeeds in bringing the electrical system back to a more stable operating point. Reverting other types of transitions is likely to require manual intervention.

**Transitions of Type D**
The electrical state of the system can also deteriorate after the system has become informationally abnormal. Again, this could happen in several ways:

D.1) The electrical state becomes abnormal because the deterioration in the state of the information infrastructure prevents the operator from becoming aware that corrective action is required.

D.2) Similarly, a failure in the information infrastructure prevents the execution of an appropriate corrective action.

D.3) Based on incorrect information or advice provided by the information infrastructure, the operator takes one or more actions that have a detrimental effect on the electrical state of the system.

D.4) The failure of a component of the information infrastructure triggers an electrical transition.

D.5) Having gained access to a part of the control infrastructure, a cyberattacker takes actions that deteriorate the electrical state of the system.

D.6) Finally, an unrelated electrical problem could arise after the state of the system has become informationally abnormal.

Transitions of type D are probably the most dangerous. They are certainly the ones that we understand the least and which deserve urgent attention from the power system community.

**Application to Past Incidents**
To demonstrate the usefulness of this framework, we have analyzed several major incidents and blackouts. Table 1 shows, for each incident, the type of the main transition that took place and contributed most to the scale of the incident. Other transitions may have occurred later as the situation degraded further.

It must be noted that the Italian blackout of 2003 and the UCTE (Western and Central Europe) incident of 2006 did not involve the failure of any electronic component. In the Italian case, it can be argued that the informational infrastructure failed because it allowed an ambiguous exchange of information by telephone between operators in Italy and Switzerland. Similarly, the UCTE incident could have been avoided if better security assessment tools had been available to the operators.

The blackout in Sweden and Denmark in 2003 has been included in this list because it is a rare exception in the sense that the report on this incident does not mention any significant failure in the information infrastructure.

**Challenges**
Table 1 suggests that failures in the information infrastructure have been at least a significant contributing factor in several major recent incidents. The obvious way to decrease the likelihood of such incidents or reduce their potential

<table>
<thead>
<tr>
<th>Incident</th>
<th>Transition</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Québec (1988)</td>
<td>D2</td>
<td>Not Available</td>
</tr>
<tr>
<td>Québec (c. 1985)</td>
<td>C3</td>
<td>Not Available</td>
</tr>
</tbody>
</table>
Consequences is to further improve the robustness of the information infrastructure. This goal requires action in several areas:

- Increase the reliability of the electronic components of the system (sensors, relays, communication devices).
- Locate network sensors strategically aiming for overall measurement robustness and possibly automatic detection of erroneous information.
- Increase the reliability of control center base software (operating system, communication).
- Enhance the robustness of the application software. For example, ensure that the state estimator still converges even when the transmission system is under stress.
- Improve the correctness of the data and the accuracy of the models used by the application software.

While it is useful for utilities, manufacturers, and software vendors to continue working on these reliability enhancement activities, there is also a need to understand in more detail how the information infrastructure can fail and what happens when it does. Such knowledge would help target improvements at the most dangerous failure modes. For example, how quickly would the electrical state of the power system degrade if the operators cannot follow its evolution because the state estimator has stopped working or they become unable to implement appropriate corrective actions because the supervisory control and data acquisition (SCADA) system has succumbed to a cyberattack?

A reliable information infrastructure provides data that reflects the true state of the system. However, what really matters is the picture of the state of the system that operators have in their mind. If this picture is incorrect, operators will not assess the situation properly or will take incorrect control actions.

The information infrastructure must therefore not only be reliable, it must also be adequate. In this context, informational adequacy has two components: scope and functionality. The scope of the information infrastructure must be sufficient for the operator to be able to assess the threats faced by the electrical system that he or she is controlling. As long as interchanges of energy with neighboring networks remained small, supplementing the utility’s own data with a sprinkling of measurements from the other side of the border and a few telephone conversations with fellow operators was sufficient. The 2003 North American Blackout and the UCTE incident of November 2006 demonstrated that this is no longer sufficient and that major problems can remain invisible to operators in interconnected systems until it is too late for them to take preventive and even corrective action. As the degree of interdependence between control areas or between national transmission networks increases, the operator must gain access to information covering an ever-widening area.

Still, all this data must be presented and processed in a way that gives the operators an accurate and easily understandable picture of the state of the system and ultimately it must help them choose the best control actions. In other words, the information must be processed and presented with the finality that it should be functional in supporting operator decision making. In that realm, collaborative work with cognitive scientists and experts in human-machine interaction could be very effective in further improving the functionality of the information infrastructure.

Conclusions

The classical framework for assessing and classifying the security of power systems assumes that the operator has a perfect picture of the state of this system. Likewise, the decision-making processes with respect to preventive and corrective control actions are also based on this assumption. In this article, we argued that failures and inadequacies in the information infrastructure invalidate this assumption.

We proposed a new framework for analyzing the impact that failures in the information infrastructure can have on the quality and reliability of the electricity supply. An analysis of major incidents using the proposed framework shows that information failures are quite often a significant contributing factor in their development and severity.

We identified some of the challenges posed by the increasing reliance on information flow in the course of power system operation. We also identified some mitigating measures which could reduce the risks associated with failures in the power system information infrastructure.

For Further Reading


Biographies

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The rapid growth of wind power in the United States and worldwide has resulted in increasing media attention to—and public awareness of—wind-generation technology. Several misunderstandings and myths have arisen due to the characteristics of wind generation, particularly because wind-energy generation only occurs when the wind is blowing. Wind power is therefore not dispatchable like conventional energy sources and delivers a variable level of power depending on the wind speed. Wind is primarily an energy resource and not a capacity resource. Its primary value is to offset fuel consumption and the resulting emissions, including carbon. Only a relatively small fraction of wind energy is typically delivered during peak and high-risk time periods; therefore, wind generators have limited capacity value. This leads to concerns about the impacts of wind power on maintaining reliability and the balance between load and generation.

This article presents answers to commonly asked questions concerning wind power. It begins by addressing the variability of wind and then discusses whether wind has capacity credit. The article addresses whether wind can stop blowing everywhere at once, the uncertainty of predicting wind generation, whether it is expensive to integrate wind

By Michael Milligan, Kevin Porter, Edgar DeMeo, Paul Denholm, Hannele Holttinen, Brendan Kirby, Nicholas Miller, Andrew Mills, Mark O’Malley, Matthew Schuerger, and Lennart Soder
power, the need for new transmission, and whether wind generation requires backup generation or dedicated energy storage. Finally, we discuss whether there is sufficient system flexibility to incorporate wind generation, whether coal is better than wind because coal has greater capacity factors, and whether there is a limit to how much wind power can be incorporated into the grid.

Can Grid Operators Deal with the Continually Changing Output of Wind Generation?
The power system—even before the development of wind-energy technologies—was designed to handle significant variability in loads. Demand varies over timescales that range from seconds to years. System operational procedures are designed around this variability and, based on analysis and operational experience, much is known about how loads vary. Very short-term changes in load (seconds to minutes) are small relative to the system peak and consist primarily of many uncorrelated events that change demand in different directions. Over longer periods (several hours), changes in demand tend to be more correlated, such as during the morning load pickup or evening load falloff.

The output of a wind power plant, or multiple wind power plants, is variable over time. Because the variability of wind is added to this already variable system, there will be some incremental variability that must be managed by the system operator. Each megawatt generated by wind reduces the required generation of other units; therefore, the remaining nonwind generation units need only supply the load that is not supplied by wind. This remaining load is often called the net load (load net of wind power). Therefore the nonwind portion of the power system is operated to the net load, which is the difference between load and wind. Figure 1 shows one week of the actual load and the net load in West Denmark. The difference between these traces is the wind generation. The load and wind can be compared more easily in Figure 2. From Figure 1 it is apparent that, at large penetration levels, wind can induce steeper ramps in both directions and can require generators to operate at reduced output. At high penetration rates, it can be difficult to manage this incremental variability if existing generators do not have the required ramping capability.

Generally, the (relative) variability of wind decreases as the generation of more wind power plants is combined. Figure 3 is taken from the wind plant data-collection

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**Figure 1.** West Denmark load and net load (load less wind), 10–16 January 2005 (source: Energinet.dk).

**Figure 2.** West Denmark load and wind, 10–16 January 2005 (source: Energinet.dk).

**Figure 3.** Comparison of second-to-second variability of wind production between (a) a wind plant with 200 wind turbines and (b) a wind plant with 15 wind turbines.
Although wind is a variable resource, grid operators have experience with managing variability that comes from handling the variability of load.

program of the National Renewable Energy Laboratory (NREL) and shows one-second data for approximately nine hours from a wind plant with several interconnection points. The data are from the same time period and are normalized to the mean output of each group of wind turbines. Figure 3(a) shows the normalized variability of 200 turbines. Figure 3(b) shows the considerable variability of a group of 15 turbines. From these data and the figure it can be concluded that the normalized wind variability is reduced with aggregation. This principle applies to small-scale and large-scale geographical aggregation and to all timescales of grid operation.

Grid operators in some countries are gaining experience with higher penetrations of wind and with the variability of wind power. Figure 4 shows the hourly wind penetration in Ireland from 7 May through 10 May 2009. Hourly wind penetration in Ireland ranges from a small percentage to as much as 40%. Similarly, Figure 1 (as noted) shows load and net load (load minus wind) in Denmark in January 2005. The figure shows that wind production increased and then decreased as wind turbines shut down because of high wind speeds. Higher wind production drove net load near zero in some hours. As is discussed later in this article, grid operators handle wind variability using existing flexible generation resources, wind forecasting, and subhourly scheduling; wind production is more predictable when evaluated closer to real time. Subhourly schedules also let grid operators access the flexibility of other generating units. Additionally, large balancing areas (or utility control areas) help with wind variability, because wind variability is smoothed over larger geographic areas.

**Does Wind Have Capacity Credit?**

The determination of whether there is sufficient installed capacity to meet loads allows for the possibility that some generation will not be able to provide capacity when needed at some future date. Generally, although the exact amount and procedures differ, system planners require a 12–15% margin of extra capacity as compared to peak load. This is known as the planning reserve margin.

The term “planning reserve” refers to the installed capacity of the generation fleet and is separate and distinct from various types of operating reserves that are based on system conditions during operations. A more rigorous approach to evaluating planning reserves is to model hourly loads, generation capacity, and the forced outage rates of generators to determine the loss of load probability (LOLP) (i.e., the probability that generation will be inadequate to serve load). The LOLP can be used to determine the loss of load expectation (LOLE) that defines how many hours per year, days per year, or days in ten years that load might not be served. A typical LOLE target is one day in ten years.

Wind can contribute to planning reserves based on its influence on system LOLE—the same way that conventional units contribute to planning reserves. In most cases, wind makes a modest contribution to planning reserves, as indicated by capacity credit in the United States that ranges from approximately 5% to 40% of wind rated capacity. The wide range of capacity credit percentages assigned to wind reflects the differences in the timing of wind-energy delivery (when the wind blows) relative to system loads and periods of system risk. Once the capacity credit that may be assigned to a wind plant has been determined, it is the job of the system planner to determine the amount of additional capacity necessary to meet the system reliability criterion, regardless of the method used to procure the capacity.

**figure 4.** Hourly wind penetration in Ireland, 7–10 May 2009.
How Often Does the Wind Stop Blowing Everywhere at the Same Time?

Individual wind turbine production is highly variable and grid operators are concerned that 100,000 MW of wind could present a severe reliability challenge. As explained above, wind benefits inherently from aggregation; therefore 100,000 MW of wind power does not behave like a single wind turbine. Aggregating wind over larger geographic areas decreases the number of hours of zero output. One wind power plant can have zero output for more than 1,000 hours during a year, whereas the output of aggregated wind power in a very large area always—or nearly always—is greater than zero. The variability also decreases as the timescale decreases. The second and minute variability of large-scale wind power generally is small; over several hours, however, there can be great variability, even for distributed wind power.

What about more significant weather events that can increase wind speed and require wind turbines to shut down for safety reasons and to protect the wind project? These events are not frequent. In some areas they do not occur every year, and in other areas they happen one to two times per year. Large storm fronts take four to six hours to pass over several hundred kilometers so, again, aggregating wind over a geographically wide area helps overcome this challenge. For a single wind turbine, generation can decrease from full power to zero very rapidly. The aggregation of wind capacity, however, turns the sudden interruption of power into a multihour downward ramp. Texas experienced this type of wind event in February 2007. Figure 5 illustrates how the output from a single wind plant dropped by 170 MW over approximately 15 minutes. Over all wind projects, the aggregate wind capacity decrease was much greater, at 1,500 MW, but it took two hours to occur. In West Denmark, the most extreme storm event so far (January 2005) took six hours to shut down nearly 90% of the rated capacity (2,000 MW).

Big storms can typically be forecast before they become threats, and large wind power plants can be required to operate at partial loads to prevent sizable ramps in case the wind speeds exceed the cutoff speed of the turbines. System operators can be notified of the potential magnitude of these events and have an opportunity to put the system in a defensive position. Control systems can also be designed to prevent all turbines from shutting down during the same minute. Lastly, large wind events are not like large conventional generator contingencies in which 1,000 or 2,000 MW can be lost instantaneously. Significant changes in wind output take hours rather than minutes, so there is time for conventional generators to ramp up. There is also time to start combustion turbines if not enough conventional generation is available.

Isn’t It Very Difficult to Predict Wind Power?

Wind-energy forecasting can be used to predict wind-energy output in advance through a variety of methods based on numerical weather prediction models and statistical approaches. Wind forecasting is a recently developed tool as compared with load forecasting, and the level of accuracy is not as great for wind forecasting as for load forecasting. The experience to date suggests that the overall shape of wind production can be predicted most of the time, but significant errors can occur in both the level and timing of wind production. Therefore, system operators will be interested in both the uncertainty around a particular forecast and the overall accuracy of the forecasts in general. Wind forecasts for shorter time horizons tend to be more accurate than forecasts over longer time horizons. For a single wind power plant, forecasts that are one to two hours ahead can achieve an accuracy level of approximately 5–7% mean absolute error (MAE) relative to installed wind capacity; this increases to 20% for day-ahead forecasts.

![Figure 5](image_url). Aggregation benefits large, rare events.
Greater levels of wind energy cannot necessarily be incorporated into the grid simply by continuing to plan and operate the system using current approaches.

There is a strong aggregation benefit for wind forecasting, as shown in Figure 6. As the figure demonstrates, aggregation over a 750-km region reduces forecasting error by about 50%. The figure shows the error reduction as the ratio between the RMSE of a regional prediction and the RMSE of a single site, based on results of measured power production of 40 wind farms in Germany. In other research conducted in Germany, typical wind-forecast errors for representative wind power forecasts for a single wind project are 10% to 15% root mean square error (RMSE) of installed wind capacity but drop to 6% to 8% for day-ahead wind forecasts for a single control area and to 5% to 7% for day-ahead wind forecasts for all of Germany. Combining different wind-forecasting models into an ensemble wind forecast can also improve wind-forecasting accuracy by up to 20%, as measured by RMSE.

More important, the impact of forecast errors for individual wind plants is not of much concern. The aggregate forecast error of all the wind plants is what drives the errors in committing and scheduling generation.

Isn’t It Very Expensive to Integrate Wind?
The wind-integration cost is the additional cost of the design and operation of the nonwind part of the power system when wind power is added to the generation mix. Generally, at wind penetrations of up to 20% by energy, the incremental balancing costs caused by wind are 10% or less of the wholesale value of the wind power. The actual impact of adding wind generation in different balancing areas (or control areas) can vary depending on several factors, such as the size of the balancing area, the resource mix, and the extent to which the wind generation is spread out geographically.

The variability of wind power does not correlate with the variability of load. This means that the existing variability of the system can absorb some wind power variability. It also means that adding this new component of variability to a power system will not result in just adding up the total and extreme variability of both, because extreme variations are not likely to coincide. Overall variability is determined by the square root of the sum of the squares of the individual variables (rather than the arithmetic sum). This means that reserves needed to balance variations in load net of wind are less than the sum of reserves needed to balance variations in the load alone or the wind alone.

The operational integration costs for wind will be less for larger balancing areas as compared with smaller balancing areas. Similarly, if the wind generation is spread over large areas, the per-unit variability decreases and the predictability of wind generation increases, leading to reduced wind-integration costs. Additional operating reserves may be needed, but that does not necessarily require new generating plants. The experience of countries and regions that already have quite a high wind penetration (from 5% to 20% of gross electric energy demand) has been that the existing reserves are deployed more often after wind power is added to the system, but no additional reserve capacity is required.

Doesn’t Wind Power Need New Transmission, and Won’t That Make Wind Expensive?
Historically in the United States, incorporating new generation sources has involved new transmission development. Federal hydropower facilities of the 1930s, 1940s, and 1950s included transmission facilities owned by the federal government. The development of large nuclear and coal plants in the 1960s and 1970s required interstate transmission facilities to deliver that energy. Similarly, transmission was constructed to access hydroelectric resources in Finland, Sweden, and Italy. Developing wind resources in the United States and internationally is also likely to involve developing new transmission. Transmission is required for meeting growth in electricity demand, to maintain electric reliability, and to access other generating resources besides wind generation needed to meet growing demand.
Several studies have found that, although the costs of building transmission to access wind resources are significant, consumers benefit from reduced energy-production costs as a result of wind generation displacing other energy resources. The Joint Coordinated System Plan (JCSP), a conceptual transmission and generation plan for the Eastern Interconnection in the United States, indicates that a 20% wind scenario by 2024 would result in a benefit-to-cost ratio of 1.7 to 1. Additionally, transmission expenditures as a percentage of the overall costs of electricity to consumers are dwarfed by the costs of electricity production (e.g., fuel, operation, and maintenance) and the capital costs needed to develop the generation. For the JCSP study, incremental transmission costs comprise 2% of the projected total wholesale energy costs for 2024.

**Doesn’t Wind Power Need Backup Generation? Isn’t More Fossil Fuel Burned with Wind Than Without, Due to Backup Requirements?**

In a power system, it is necessary to maintain a continuous balance between production and consumption. System operators deploy controllable generation to follow the change in total demand, not the variation from a single generator or customer load. When wind is added to the system, the variability in the net load becomes the operating target for the system operator. It is not necessary and, indeed, it would be quite costly for grid operators to follow the variation in generation from a single generating plant or customer load. “Backup” generating plants dedicated to wind plants—or to any other generation plant or load for that matter—are not required, and would actually be a poor and unnecessarily costly use of power-generation resources.

Regarding whether the addition of wind generation results in more combustion of fossil fuels, a wind-generated kilowatthour displaces a kilowatthour that would have been generated by another source—usually one that burns a fossil fuel. The wind-generated kilowatthour therefore avoids the fuel consumption and emissions associated with that fossil-fuel kilowatthour. The incremental reserves (spinning or nonspinning) required by wind’s variability and uncertainty, however, themselves consume fuel and release emissions, so the net savings are somewhat reduced. But what quantity of reserves is required? Numerous studies conducted to date—many of which have been summarized in previous wind-specific special issues of IEEE Power & Energy Magazine—have found that the reserves required by wind are only a small fraction of the aggregate wind generation and vary with the level of wind output. Generally, some of these reserves are spinning and some are nonspinning. The regulating and load-following plants could be forced to operate at a reduced level of efficiency, resulting in increased fuel consumption and increased emissions per unit of output.

A conservative example serves to illustrate the fuel-consumption and emissions impacts stemming from wind’s regulation requirements. Compare three situations: 1) a block of energy is provided by fossil-fueled plants; 2) the same block of energy is provided by wind plants that require no incremental reserves; and 3) the same block of energy is provided by wind plants that do have incremental reserve requirements. It is assumed that the average fleet fossil-fuel efficiency is unchanged between situations one and two. This might not be precisely correct, but a sophisticated operational simulation is required to address this issue quantitatively. In fact, this has been done in several studies, which bear out the general conclusions reached in this simple example.

In situation one, an amount of fuel is burned to produce the block of energy. In situation two, all of that fuel is saved and all of the associated emissions are avoided. In situation three, it is assumed that 3% of the fossil generation is needed to provide reserves, all of these reserves are spinning, and that this generation incurs a 25% efficiency penalty. The corresponding fuel consumption necessary to provide the needed reserves is then 4% of the fuel required to generate the entire block of energy. Hence, the actual fuel and emissions savings percentage in situation three relative to situation one is 96% rather than 100%. The great majority of initially estimated fuel savings does in fact occur, however, and the notion that wind’s variations would actually increase system fuel consumption does not withstand scrutiny.

A study conducted by the United Kingdom Energy Research Center (UKERC) supports this example. UKERC reviewed four studies that directly addressed whether there are greater CO2 emissions from adding wind generation due to increasing operating reserves and operating fossil-fuel plants at a reduced efficiency level. The UKERC determined that the “efficiency penalty” was negligible to 7% for wind penetrations of up to 20%.

**Does Wind Need Storage?**

The fact that “the wind doesn’t always blow” is often used to suggest the need for dedicated energy storage to handle fluctuations in the generation of wind power. Such viewpoints, however, ignore the realities of both grid operation and the
performance of a large, spatially
diverse wind-generation resource.
Historically, all other variation (for
example, that due to system loads,
generation-commitment and dis-
patch changes, and network topol-
ygy changes) has been handled
systemically. This is because the
diversity of need leads to much
lower costs when variability is
aggregated before being balanced.
Storage is almost never “coupled”
with any single energy source—it
is most economic when operated to
maximize the economic benefit to
an entire system. Storage is nearly
always beneficial to the grid,
but this benefit must be weighed
against its cost. With more than
26 GW of wind power currently
operating in the United States and
more than 65 GW of wind energy operating in Europe (as
of the date of this writing), no additional storage has been
added to the systems to balance wind. Storage has value in
a system without wind, which is the reason why about 20 GW
of pumped hydro storage was built in the United States and
100 GW was built worldwide, decades before wind and solar
energy were considered as viable electricity generation tech-
nologies. Additional wind could increase the value of energy
storage in the grid as a whole, but storage would continue to
provide its services to the grid—storing energy from a mix
of sources and responding to variations in the net demand,
not just wind.

As an example, consider Figure 7 below, which is based
on a simplified example of a dispatch model that approxi-
mates the western United States. All numerical values are
illustrative only, and the storage analysis is based on a hypo-
thetical storage facility that is limited to 10% of the peak
load and 168 hours of energy. The ability of the system to
integrate large penetrations of wind depends heavily on the
mix of other generation resources. Storage is an example of
a flexible resource, and storage has economic value to the
system even without any wind energy. As wind is added to
the system in increasing amounts, the value of storage will
increase. With no wind, storage has a value of more than
US$1,000/kW, indicating that a storage device that costs less
would provide economic value to the system. As wind pen-
etration increases, so does the value of storage, eventually
reaching approximately US$1,600/kW. In this example sys-
tem, the generation mix is similar to what is found today in
many parts of the United States. In such a system with high
wind penetration, the value of storage is somewhat greater
because the economic dispatch will result in putting low-
variable-cost units (e.g., coal or nuclear) on the margin (and
setting the market-clearing price) much more often than it
would have without the wind. More frequent periods with
lower prices offers a bigger price spread and more opportuni-
ties for arbitrage, increasing the value of storage.

In a system with less base load and more flexible genera-
tion, the value of storage is relatively insensitive to the wind
penetration. Figure 8 shows that storage still has value with
no wind on the system, but there is a very slight increase in
the value of storage even at a wind-penetration rate of 40%
(energy). An across-the-board decrease in market prices
reduces the incentives for a unit with high fixed costs and
low variable costs (e.g., coal or nuclear) to be built in the
first place. This means that in a high-wind future, fewer low-
variable-cost units will be built. This reduces the amount of
time that low-variable-cost units are on the margin and also
reduces the value of storage relative to the “near-term” value
with the same amount of wind.

The question of whether wind needs storage ultimately
comes down to economic costs and benefits. More than a
dozen studies analyzing the costs of large-scale grid inte-
gration of wind come to varying conclusions, but the most
significant is that integration costs are moderate, even with
up to 20% wind-energy penetration, and that no additional
storage is necessary to integrate up to 20% wind energy in
large balancing areas. Overall, these studies imply that the
added cost of integrating wind over the next decade is far
less than the cost of dedicated energy storage, and that the
cost can potentially be reduced by the use of advanced wind-
forecasting techniques.

Isn’t All the Existing
Flexibility Already Used Up?
The conventional generation mix is designed with a great
deal of flexibility to manage the daily load cycle. Interme-
diate and peaking units must be designed to cycle and to
serve load. Only base-load generators operate continuously. As a result, for many balancing areas the nature of the daily load cycle has resulted in a conventional-generation fleet with significant maneuvering capability. Figure 9 provides an example of an illustrative utility system.

The existing mix of conventional generators typically has much more maneuvering capability than that required by the power system to meet the daily load cycle. An analysis of the excess thermal generation online ramping capability in three different balancing areas is shown in Figure 10.

Subhourly energy markets or subhourly scheduling of generation provides access to the physical maneuvering capability of conventional generators. Regions where generators are only allowed to change schedules hourly do not enable access to all existing capability—but this is because of market rules in these areas and not because generators lack the capability. Large regional transmission organizations (RTOs) in the United States, for example, have successfully operated subhourly energy markets for a number of years. Aggregation further reduces the relative variability of great amounts of wind. The net load variability increases less than linearly, and the ramping capability adds linearly.

New types of conventional-generation technology could also help. Newer combustion turbines and some newer reciprocating-engine plants offer better efficiency than older combustion turbines and have a broader operating range, lower minimum loads, fast ramping, and near-zero start-up costs. When installed, these units increase the response capability of the conventional-generation fleet.

Interconnections with neighboring systems can also provide flexibility by enabling balancing among different areas. In Europe, it is possible to balance net variability and generation response throughout the Nordic system. Hydro plants in Finland respond to net variability in the system all the way to Denmark—a distance of 1,400 km—if this is the least-expensive option and if transmission between Finland and Denmark through Sweden is available.

Demand response offers new flexibility for system operators. Smart grids could provide access to the response capability of existing loads. Plug-in hybrid electric vehicles promise to increase minimum loads at night—making use of surplus wind-energy generation—and to offer fast and accurate response to high variability in wind net load, as needed by the system operator.

**Is Wind Power as Good as Coal or Nuclear Even Though the Capacity Factor of Wind Power Is So Much Less?**

When comparing power plant options from an economic standpoint, two key questions arise: 1) what capital investment in generating equipment is required to produce a given amount of generated electrical energy? and 2) what are the operating costs associated with that amount of energy? The capital investment costs are typically amortized over the amount of energy produced so, with respect to the first question, a plant costing \( C \) and producing an amount of energy \( E \) is equivalent to a plant costing \( 2C \) and producing energy in the amount of \( 2E \).

Current estimates for new coal plants range from some US$3,000/kW to US$4,000/kW, and estimates for nuclear plants—although difficult to obtain because so few plants have been built over the last 20 years—range from US$4,000/kW to US$8,000/kW. Current wind plant cost
estimates range from US$2,000/kW to US$2,500/kW. Coal and nuclear plants, however, generally have greater capacity factors; a kilowatt of wind installed capacity thus produces less energy over a year than does a kilowatt of installed coal or nuclear capacity. A wind plant located in a good wind resource area has a 35–45% capacity factor, but coal and nuclear capacity factors range from about 60% to 90%.

With respect to capital cost per unit of energy produced, a US$2,500/kW wind plant with a 40% capacity factor, a US$3,750/kW coal plant with a 60% capacity factor and a US$5,000/kW nuclear plant with an 80% capacity factor are all equivalent. Of course the operating costs—primarily fuel and maintenance costs—will differ for these plants. But fuel costs are low for coal and nuclear plants, and wind plants have no fuel costs. So in all three cases, operating costs contribute a small amount to the overall energy costs relative to the capital cost contribution.

Wind also compares favorably with wholesale power prices. Figure 11 shows the minimum and maximum of average wholesale power prices for a flat block of power from 2003 through 2008. The red dots indicate the total capacity-weighted average price that wind projects received in each year, with the wind projects having online dates

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**Figure 10.** An analysis of three different balancing areas showed that all three have excess load-following capability inherent in the conventional thermal-generation mix.

**Figure 11.** Average cumulative wind and wholesale power prices over time. Source: Annual Report on U.S. Wind Energy Markets: 2008 (U.S. Department of Energy).
from 1998 through 2008. On a cumulative basis within the sample of projects in the figure, average wind power prices have been at or below the low end of the wholesale power price range.

Plant capacity factors also reflect the functions that different power technologies perform. Generators have different capacity factors, depending on whether they are used as base-load, cycling, or peaking units. For example, nuclear and coal generators are primarily base-load units that have high capacity factors. Wind and hydro generate energy that is basically free; wind is taken when available and hydro is scheduled to deliver the maximum value to the grid (when possible). Technologies having lower capacity factors (combined cycle, combustion turbines, oil- and gas-fired steam boilers) operate as peaking and load-following plants and as capacity resources. The capacity factors of individual plants may be affected by environmental requirements, such as a limitation on the number of hours a peaking fossil-fuel unit may operate because of air quality regulations. In addition, market factors may also reduce plant capacity factors. For example, high natural gas prices may reduce the operation of natural gas plants. Overall, many resources operate at less-than-rated capacity but play an important part in ensuring system reliability. This situation is illustrated by a snapshot of one year of operating data from the MISO market, as shown in Figure 12.

Isn’t There a Limit to How Much Wind Can Be Accommodated by the Grid?

Although wind is a variable resource, operating experience and detailed wind-integration studies have yet to find a credible and firm technical limit to the amount of wind energy that can be accommodated by electrical grids. Some countries already receive a significant amount of electricity from wind power. Denmark receives about 20% of its electricity from wind power (43% of peak load), and Germany has reached the level of 7% wind-energy penetration (30% of peak load). Spain and Portugal have each reached wind-energy penetration levels of 11% (30% of peak load), with a limited interconnection to the rest of Europe. Ireland has an island system with 9% wind-energy penetration (11% of peak load). There is not a technical limit to increased penetration of wind energy, but there might be an economic limit—a point at which it is deemed too expensive to accommodate more energy from wind in comparison with the value that it adds to the system. Years of worldwide experience in operating power systems with significant amounts of wind energy and detailed integration studies have shown that the increase in costs to accommodate wind can be modest, and that the value of additional wind energy does not decline as precipitously as once expected. More directly, it has been shown that large interconnected power grids can accommodate variable generation (wind and solar) at levels of 25% of peak load. Studies examining even greater levels of wind penetration are under way for both the Eastern and Western interconnections in the United States.

Greater levels of wind energy, however, cannot necessarily be incorporated into the grid simply by continuing to plan and operate the system using current approaches. Reaching these increased levels of wind penetration requires investments in infrastructure such as new transmission, potential changes to market rules, and incentives or requirements to generation owners.
and transmission operators to better utilize technology and existing assets. Utility planners and those investing in new plants must consider flexibility in procurement decisions to meet load growth or to replace retiring generators. More flexibility includes reduced minimum generation levels, greater ramp rates, quicker start times, and designs that allow frequent cycling without increasing material fatigue or reducing component lifetimes. Markets and tariffs also need to be designed to reward increased flexibility.

Wind plants can offer increased flexibility through the provision of ancillary services. In some cases, the least-cost dispatch decision might be to curtail the output of a wind plant by limiting its ramp rate, back the wind plant down from its maximum potential production level for a short period, or have the wind plant provide active power regulation. As wind technology matures, wind plants could move toward provision of reactive power, voltage control, and power frequency/governor droop (the decrease in frequency to which a governor responds by causing a generator to go from no load to full load) functions.

Summary

The natural variability of wind power makes it different from other generating technologies, which can give rise to questions about how wind power can be integrated into the grid successfully. This article aims to answer several important questions that can be raised with regard to wind power. Although wind is a variable resource, grid operators have experience with managing variability that comes from handling the variability of load. As a result, in many instances the power system is equipped to handle variability. Wind power is not expensive to integrate, nor does it require dedicated backup generation or storage. Developments in tools such as wind forecasting also aid in integrating wind power. Integrating wind can be aided by enlarging balancing areas and moving to subhourly scheduling, which enable grid operators to access a deeper stack of generating resources and take advantage of the smoothing of wind output due to geographic diversity. Continued improvements in new conventional-generation technologies and the emergence of demand response, smart grids, and new technologies such as plug-in hybrids will also help with wind integration.

For Further Reading


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WIND, SOLAR, AND OTHER RENEWABLE ENERGY resources are an important part of any present-day energy plan, and the portion of energy they supply to the power grid will certainly be increasing over the next few decades. Arguably, large-scale wind power has reached technological maturity, and with more than 100 GW of capacity installed globally, ample experience exists on integrating wind energy into power systems. Solar technologies, on the other hand, are still emerging, and substantial R&D investments are being made to achieve parity with retail electricity costs in the near future. As this happens, annual capacity additions of solar power will become significant.

As the levels of penetration rise, the technical impact of renewable energy on grid operation could lead to the creation of market barriers that would ultimately limit further penetration of renewable energy. Recognizing these risks, the U.S. Department of Energy (DOE) launched the “Renewable System Interconnection” (RSI) study in early 2007. The department brought together a team of industry experts to produce 15 reports that identify the technical and analytical challenges that must be addressed to enable high penetration levels of distributed renewable energy technologies. GE Global Research, the research lab of the General Electric Co., was part of the team, and we worked closely with the National Renewable Energy Laboratory (NREL) to contribute four of the reports, which addressed aspects of planning for large-scale solar power integration with the utility system. Although the experience gleaned from the grid integration of wind power will certainly be helpful, integrating the sizable
capacities of solar power will present a new set of challenges and opportunities.

The key difference between wind and solar energy with respect to their integration into power systems is the scale at which they are cost effective. Cost-effective wind power typically implies multimegawatt farms that connect directly to the transmission system. Yet many promising solar technologies are expected to be cost-effective at a kilowatt scale and interconnected to distribution systems. This difference is key to understanding many assumptions of the RSI study, and it is important to highlight two of its most influential effects.

1) The practicality of solar power at the kilowatt scale lowers the barrier to entry so significantly that any electric customer may readily adopt it, leading to expectations of an extremely sharp rise in solar penetration as soon as the parity with retail electricity costs is reached.

2) With its pervasive appeal, solar electric generation is likely to interconnect as a distributed energy resource—that is, it will often be located on the customer’s side of the meter to offset the connected load, while possibly feeding energy back to the system during some periods.

The first effect justifies the bold assumptions about the penetration of solar photovoltaic (PV) generation made by the RSI study. The DOE challenged the enlisted team of experts to move away from the customary mindset of retrofitting small quantities of solar power into the existing grid and instead to think about how things might change if the level of solar penetration were as high as 10–50%.

On its face, the second effect appears advantageous: Modern codes and standards (e.g., UL 1741 and IEEE 1547) that define the interconnection requirements for distributed energy resources already exist, so the equipment for their integration can be readily manufactured and certified. Yet, these requirements were developed under the important implicit assumption of much lower penetration. Essentially, they aim to ensure the best compatibility of distributed resources with the existing grid rather than to optimize a possible system design in which the grid evolves to accommodate a high penetration of renewable resources. Therefore, the RSI study set out to examine the suitability of the current codes and standards in guiding the massive deployment of distributed solar power as envisioned and to define a path for evolving the requirements to ensure better overall system design. In support of this vision, the DOE also asked the team to assume plentiful availability of grid-control technologies and energy storage.

The studies contributed by GE Global Research reviewed the impact of a high penetration of solar energy at different scales of the power system.

- At the scale of an independent system operator—the largest scale—we looked at how the high penetration of solar power would impact the practices of power system planning.
- At the scale of a regional transmission operator, we looked at post-contingency dynamics, and we evaluated voltage and frequency recovery under different assumptions of solar penetration and strategies for the commitment of spinning reserves.
- At the scale of a distribution company, we looked at the impact a high penetration of solar power would have on feeder voltage control, and we evaluated the voltage profile under varying assumptions regarding the coordination between inverters and utility equipment.
- Finally, at the scale of a home, we evaluated the opportunity for combining solar electricity production with energy storage to achieve improved reliability.

**Impact of High-Penetration Solar Generation on Power System Planning and Operations**

The key challenge in integrating renewable energy sources into power systems arises from the variability of these sources. The output of solar electric generation is directly proportional to insolation—or incident solar radiation—so it naturally varies over time (predictably with the sun’s location in the sky and more randomly with cloud coverage). This variability of output is illustrated in Figure 1, which compares actual solar resource data with the load of the California Independent System Operator (CAISO) in July 2007. Hourly data samples of load and solar resource are plotted for every day of the month, overlaid on the same 24-h graph. The figure represents a substantial penetration of solar power: 30% relative to peak load. Load data are shown in blue; solar resource data are shown in orange; and their difference, termed “net load,” is shown in green.

![Figure 1](image_url)
Solar technologies are still emerging, and substantial R&D investments are being made to achieve parity with retail electricity costs in the near future.

The net load concept, recognizable from wind integration studies, is useful because it combines two variable quantities (the load and the renewable resource) into one. The net load can now be used in place of the system load for the purpose of generation capacity planning, and the process is analogous to a well-established one—the conventional process of planning capacity to meet system load.

To operate power systems at constant frequency, generation must exactly match the load. Therefore, the frequency of a power system is regulated by continuously adjusting the output of on-line generation to match the load. The load varies with the time of day and season of the year, and to ensure reliable electric service, there must always be sufficient generation available to serve it. There are two parts to ensuring this sufficiency: first, adequate generation capacity must be available, and second, the available generation has to be committed each day (i.e., brought on line to “follow” the load). How these processes normally work might change with a high penetration of solar power.

Capacity planning operates on two distinct time scales. Long-term, multiyear planning deals with the construction of power plants to keep up with load growth and make up for the retirement of older power plants. Short-term planning deals with maintenance scheduling of existing power plants, typically over a one-year time horizon, to ensure there is sufficient and diverse capacity to supply the load in any week of the year as well as enough extra capacity to accommodate any unplanned outages. Capacity planning thus amounts to careful preparation for the operation stage—the day-to-day operation of the power system throughout the year. In setting up for each operating day, a load forecast is prepared one or more days ahead of time, and a unit commitment schedule is then developed to match it. Assuming that all technical constraints are met, the commitment is developed by ranking units based on operating costs to achieve the most competitive mix of generation for the forecasted load. As a result, firm orders are given to units to come on line and produce power at a scheduled time on the next day and to go off line at a different time. The total number of committed units at any given hour of the day is kept sufficient to feed the load and allow for any unplanned generation outages.

The processes are amenable to using net load in place of system load because they are designed for scheduling firm generation against the varying load. By using net load—and thus combining two varying quantities into one—the new problem is reduced to a common problem that has a familiar solution process.

However, it is important to recognize that adding the variability of renewable generation to the existing variability of the load results in higher per-unit variability of the net load compared with the load. The outcome is a more demanding operation of the dispatchable generation portfolio; that is, nonrenewable generators now have to maneuver more to accommodate the combined variability of the load and renewable sources. This increases the operating costs per unit of energy from dispatchable generation and amounts to additional operating costs, called the “integration costs” of renewable energy.

Consider again Figure 1. Introducing 30% penetration of solar power results in substantially modified shapes of average curves. Simple inspection of the average traces reveals that minimum average net load occurs at 11 a.m., while minimum average system load occurs at 4 a.m. This may lead to significant changes in commitment scheduling. For instance, the morning start of coal plants may have to be delayed, resulting in different system-wide operating costs. Furthermore, average net load rise (occurring between 1 p.m. and 5 p.m.) is evidently steeper than average system load rise (occurring between 8 a.m. and 10 a.m.), and it is sustained over a longer time period. This leads to questions about the technical capabilities of committed units to follow the load or, conversely, to a different commitment so that load following becomes possible. Note that accurately evaluating load-following requirements for net load calls for a more comprehensive set of load and resource data than those shown in Figure 1; higher sampling frequency and data collection over several years are necessary to extract adequate descriptive statistics. Interested readers are encouraged to probe further by reviewing some of the recent wind studies prepared by GE.

Key Conclusions
Experience in integrating wind energy has already changed system-planning practices: Generation planning is shifting from planning for peak load toward planning for system energy. This shift is centered on using net load as a basis for capacity planning, and this creates a set of requirements for reliable and comprehensive renewable-resource data. Furthermore, a new dimension is being introduced into generation planning—the need for explicit evaluation of generation flexibility relative to the variability of net load at the time scale of load following. Increased penetration of intermittent renewable generation means that the operational flexibility of the balance of the generation...
portfolio will become strategically important; the lack of flexibility will inevitably result in curtailment of renewable generation. To avoid this, more flexibility must be provided. Such flexibility can be achieved in three essential ways: by balancing the generation portfolio, load control, and energy storage. This process can be accelerated by targeted R&D investment and the creation of efficient markets to address future load-following needs. Quantifying the variability to determine required flexibility also requires correlated historical load and resource data at time scales that are not being collected. Integrating renewable-resource data into generation planning will be an important area of future work.

Transmission System Performance for High-Penetration Solar PV

The commercial viability of renewable sources of generation is directly influenced by the quality of the renewable resource (e.g., average wind speed, average solar insolation, capacity factor), and it is reasonable to expect a higher concentration of renewable sources of generation in geographical areas with the highest quality of the resource. Some areas may reach penetration percentages sufficient to affect dynamic stability of the transmission system to which they are connected. (The massive installation of wind generation in some areas of the world, such as Spain and northern Germany, proved to have a substantial impact on power-system performance.) For example, transmission faults that were previously characterized by short voltage sags can become significant system events with large power-imbalance issues between control zones due to the considerable amount of wind generation that becomes disconnected because of insufficient fault tolerance. As a result, wind-generation technologies are being required to provide enhanced performance characteristics, such as tolerance to voltage sags. Although PV generation is more distributed in nature than wind generation is, many of the concerns regarding significant wind penetration are relevant to PV penetration as well.

We analyzed transmission-system performance under various assumptions about the deployment of solar PV and the degree to which its properties complied with the recommendations of IEEE 1547. The transmission-system database selected for this analysis is based on the well-known IEEE 39 bus system. Different load levels, PV penetration levels, unit commitment strategies, and primary reserve distributions were studied. Figure 2 compares eight basic scenarios for how high-penetration solar PV could possibly be deployed. System load is represented on the abscissa, and the deployment scenarios studied are identified using horizontal bar charts representative of each scenario’s commitment strategy. Starting from the top, scenario 1 represents a baseline scenario with high load. System demand is equal to about 6,600 MW, of which some 5,600 MW are met by thermal generation within the area (blue part of the bar chart), and the remaining 1,000 MW are met by imports (purple part of the bar chart). Scenario 2 represents the same system with low load demand of about 3,200 MW, of which some 3,050 MW are met by thermal generation within the area, and about 150 MW are imported. With respect to the deployment of new renewable generation, two extreme assumptions are possible. One is that new renewable generation is being used to meet load growth, resulting in high and low load scenarios (scenarios 3 and 4). In both cases, load demand is increased by about 2,000 MW, and this demand is met entirely by generation from solar PV (shown as a yellow segment of the bar chart). The other extreme deployment assumption is one in which renewable generation displaces traditional generation, giving us additional options for the commitment of generation reserves (scenarios 5–8). Scenarios 5 and 6 represent high and low demand with the local thermal generation decommitted (taken off line) to “make room” for renewable generation. Scenarios 7 and 8 maintain the thermal generation on line, but its power output is reduced to allow for power supply from renewable generation. These generation reserves (the purple segments of the associated bar charts) are approximately equal to the output from solar generation (yellow segments of the chart). The last two scenarios represent the highest cost per unit of thermal generation; they overcommit thermal plants and then operate them at lower than optimal heat rates.

The contingencies studied in these scenarios were loss of import, loss of load, and the fault at one of the buses followed by the clearing of one of the connected lines.

Multiple simulations were run to assess the effect of PV penetration on transmission-system reliability. Conventional cases (PV using disconnection criteria according to IEEE 1547) were compared with cases using frequency control and no over-frequency trips as well as with cases involving low-voltage ride-through, voltage control, anti-islanding, and situations with large motor loads.

**Figure 2.** Deployment scenarios for high-penetration solar PV.
The key difference between wind and solar energy with respect to their integration into power systems is the scale at which they are cost effective.

**Key Conclusions**

We made a number of observations about the stability of transmission systems with high-penetration PV.

1) Unit commitment strategy has a significant impact on system performance.
   - System inertia and frequency regulation capabilities are reduced as conventional generation is decommitted.
   - Depending on the chosen level of reserves, thermal units may operate at reduced efficiencies.
   - Reactive power support in the transmission system is reduced as conventional generation is decommitted.

2) Considerable dispatch flexibility of conventional generation is required to accommodate high-penetration PV.

3) With substantial PV generation that is compliant with IEEE 1547, system reliability is considerably reduced because of the extensive loss of PV generation during transmission faults.

4) PV generation could provide primary frequency control for frequency excursions that are above nominal without significantly reducing energy production.

5) Anti-islanding schemes of PV can adversely affect the oscillatory stability of the bulk power system.

6) Adding low-voltage ride-through capability to PV systems improves the reliability of transmission systems with high-penetration PV.

7) Even if the PV stays connected during and after a system fault, post-fault voltage sags limit its available power output. Because IEEE 1547 does not permit PV inverters to respond to grid reactive power requirements (i.e., to regulate voltage), post-fault voltage recovery takes longer than it does in cases using traditional generation. Although not observed in the specific scenarios simulated in our study, lack of post-fault reactive power support can result in system voltage collapse.

Future work should concentrate on developing accurate models for estimating the aggregate behavior of PV systems. Special attention should be paid to representing the behavior of PV sources during and after system faults. Additionally, explicit guidelines should be developed for modeling the medium- and low-voltage networks to which PV sources connect.

**Distribution System Voltage Performance for High-Penetration Solar PV**

Currently, electrical distribution systems are designed and operated based on the assumption of centralized generation and the corollary that power always flows from the distribution substation to end-use customers. With the increasing penetration of residential and commercial PV at the point of end use, PV power generation would not only offset the load, but also could cause reverse power flow through the distribution system.

Significant reverse power flow may cause operational issues for the traditional distribution system, including:

- Overvoltage on the distribution feeder (loss of voltage regulation)
- Incorrect operations of control equipment, which may lead to an increase in the number of operations and related equipment wear or to further aggravation of problems that affect more equipment and more customers.

Independent of power flow direction, connecting generation resources to a distribution feeder can introduce sources of short-circuit current contribution to the distribution system. This could possibly result in:

- Increased short-circuit currents, potentially reaching damaging levels
- Protection desensitization and a potential breach of protection coordination.

However, because PV is interfaced to the grid via inverters that must operate in a manner that protects the sensitive power electronics, PV tends to create short-circuit contributions of far less magnitude than would be produced by distributed generation using rotating generators.

Among the distribution integration issues, voltage regulation issues stand out because they directly correlate to the amount of reverse power flow. We studied reverse power flow under different assumptions of inverter participation in feeder voltage control. Although current interconnection requirements prohibit inverters from controlling voltage, modern inverters are generally capable of supplying reactive power (Q) to the system and thus participating in voltage control. This capability has quantifiable boundaries. At one extreme, if no power is being produced by the PV array (as in the early evening, after sunset), an inverter can use its entire rating to supply Q. At the other extreme, when the PV array is producing its full rated power, the inverter has no Q capability unless it is intentionally oversized. It is important to recognize that moderate oversizing results in significant Q capacity. As shown in Figure 3, increasing the inverter size by 10% increases the reactive power capability from zero to nearly 46% during the maximum PV power generation condition. This will provide a power factor range from unity to 0.91 leading/lagging. Of course, the Q capacity during the “no-sun condition” will also be increased; neglecting
more elaborate design considerations, we used 110% as the "no-sun Q capability."

Our study put this Q capacity into action on an example distribution feeder to evaluate the effects an inverter may have on the voltage profile and feeder Q flow. A representative distribution system was based on a previous study of distributed generation conducted by GE Global Research and NREL. A simplified schematic is shown in Figure 4. The system includes voltage regulators at the substation and along the feeder, switched capacitors, and distribution transformers. To explicitly investigate the voltage at the customer service entrance, we added a representation of service transformers and secondary circuits to the original model. Solar PV generation capacity was distributed evenly throughout the test system, scaled in proportion to the nodal loads; thus, when 30% penetration is assumed, a 1-MW load at a bus is combined with a PV installation comprising a 300-kW PV panel and a 330-kVA inverter.

Voltage profiles and the associated active and reactive power flows for the case of peak system load with no PV generation (no sun) are compared in Figure 5. Figure 5(a) and (b) assumes no inverter participation in voltage control; the inverters are essentially operating under the guidance of IEEE 1547. Figure 5(a) shows the feeder voltage profile and, indirectly, the participation of utility equipment in controlling the voltage profile. Beginning at the substation (from the left), the voltage starts near the high end of the range and decays along the length of the feeder due to voltage drops caused by load current. At about 2 mi from the substation, voltage is stepped up again by another voltage regulator and then decays monotonically to the end of the feeder. Voltage limits, based on ANSI C84.1, are plotted as pairs of horizontal lines: The red pair represents the service voltage limits specified by the standard, and the green pair specifies the corresponding feeder voltage limits, usually set by the utility to indirectly control service voltage. The calculated feeder voltage profile is shown as a solid blue line, and at each load node, a vertical line segment drops down to designate the voltage drop across the service transformer and the secondary distribution. The solid dot at the end of the vertical line segment is the calculated service voltage at the load. Successful voltage regulation requires that the feeder voltage profile ("solid blue line") remains between the "green limits" and that the "solid dots" at the end of the "vertical line segments" remain between the "red limits." Figure 5(b) shows the active and reactive power flow on this feeder; the Q injection by the shunt capacitor is evident about 3.6 mi from the substation.

Figure 5(c) and (d) represents the case of 50% penetration of solar PV and active participation of the PV inverters in feeder voltage control. In the no-sun condition, the entire MVA rating of the inverters is used to supply the reactive power of the feeder. As a result, the voltage profile in Figure 5(c) is controlled to within tighter tolerance than the voltage profile in Figure 5(a); this is enabled by a more distributed injection of reactive power. Inspection of the associated active and reactive flows in Figure 5(d) shows the significant reduction of reactive power flow. With the PV inverters supplying reactive power locally, almost no Q needs to come from the substation. This condition has an important economic benefit—namely, feeder losses are reduced since the feeder current now has a lower magnitude.

Now, consider two scenarios of power export, illustrated in Figure 6. We studied the condition of 50% penetration of solar PV and, for simplicity, assumed that feeder load is zero, resulting in 50% reverse power flow. Two voltage control strategies are compared. Figure 6(a) and (b) assumes that inverters are controlled to provide 1 p.u. voltage in the primary circuit, resulting in a relatively flat voltage profile along the feeder—a seemingly desirable condition. However, closer inspection of Figure 6(b) reveals substantial reactive power flow from the system toward the inverters, which is a serious disadvantage of this control strategy.
IEEE 1547 and other standards should evolve to allow distributed resources to play an active role in distribution system operations and accommodate the increasing penetration of PV systems.

Remember that driving power flow along the feeder generally requires a descending voltage slope. Therefore, combining the objectives of driving power flow and maintaining the flat voltage profile creates an undesired condition: The inverters are forced to consume reactive power. This condition is detrimental from the standpoint of integration since the aggregate PV generator associated with this distribution feeder does not provide its fair share of reactive power to the host power system. In fact, it increases the reactive loading of other generators in the system.

In contrast, coordinated control of the inverters and utility equipment, as shown in Figure 6(c) and (d), enables inverters to supply their fair share of reactive power to the host power system while maintaining the voltage within prescribed tolerances. Coordinated control of the inverters and utility equipment is evident from the voltage profile shown in Figure 6(c); the tap changer in the substation is now at a low end of its range to allow a rising voltage profile along the length of the feeder. The voltage regulator within the feeder now steps down the voltage to allow for its rise toward the end of the feeder. The voltage drops that occur across service transformers and secondary distribution now have a different sign: The line segments point up, indicating higher per unit voltage at the load relative to the feeder.

**Figure 5.** Case of peak load and no sun: (a) voltage profile with no inverter participation, (b) corresponding P and Q flow, (c) voltage profile with 50% PV penetration and entire inverter capacity used for Q supply, and (d) corresponding P and Q flow.
Key Conclusions

Coordinated control of utility equipment and distributed generators can be used to enhance the performance of distribution systems. As demonstrated in our subset of simulations, the distributed fleet of PV systems can be controlled to ensure that, under exporting situations, the distribution feeder provides its fair share of reactive power back to the grid, as is required of all other conventional generators.

Future work should concentrate on developing a set of recommended practices for modeling PV inverters for load flow analysis and other relevant planning purposes, such as short-circuit current calculations. This would result in a more consistent understanding of the issues across the industry, and it would simplify the test-case setup so that it becomes possible to evaluate any specific situation.

Enhanced Reliability of PV Systems with Energy Storage and Controls

In our study, PV generation, load control, and battery energy-storage systems were managed to enhance service reliability for the customer. During a utility interruption, customers within a community are able to intentionally island, reconfigure total loads into only the critical loads, and meet the critical loads by managing PV and energy storage. The objective of our study was to evaluate the improvement in reliability associated with this capability. The typical reliability indices used by utilities were redefined to account for critical loads only. Thus, if the infrastructure within a home is sufficient to enable uninterrupted service of critical loads, no penalty for interruption is taken. The study considered only the energy balance of loads and supply. Technical challenges related to graceful disconnection from the failing grid, load in-rushes and protection, and the commercial and legal complexities of setting up for energy exchange within a community were intentionally “overlooked” to allow for a rough quantification of possible benefits and help us decide whether more detailed work is justified.

We studied three U.S. sites (in New Jersey, Colorado, and California) using site-specific resource data.
and home construction style, which drove the assumptions on heating and air conditioning. The simulations were set up for different community sizes to exploit the coincidence factor of loads, and they were based on historical outage frequency and duration. We made assumptions about reasonable critical loads based on published data on appliance energy consumption and our best judgment. Owing to the proximity of the Colorado site to NREL, the resource and weather data from that site had the best fidelity.

In Figure 7 and Figure 8, the enhancements in our adopted critical reliability indices are presented for a 100-home community in Golden, Colorado. We considered a range of battery sizes and PV penetration levels.

Based on these results, a community with no energy storage (0 kWh) and no PV (0%) will experience no enhancement in reliability (100% of original index). For validation, this was observed for both the index in Figure 7 and the index in Figure 8. As PV increases, reliability improves, which is suggested by a reduction in the corresponding index (a decrease in average outage duration and frequency amounts to an improvement in reliability). Similarly, as the battery capacity increases, reliability improves. The improvement in reliability is more substantial when the size of

**Figure 7.** Critical system average interruption duration index (SAIDI) for a 100-home community in Golden, Colorado.

**Figure 8.** Critical system average interruption frequency index (SAIFI) for a 100-home community in Golden, Colorado.
Within the home, a combination of energy storage and PV may enhance the reliability of power supply in the event of an outage.

the battery increases than when PV penetration increases. This is a logical conclusion because a charged battery is available to meet the critical load of a home during an outage at any and all hours of the day, independent of the presence of sunlight. Similar trends in reliability enhancement were observed for the other two geographical regions.

**Key Conclusions**
The results of our study suggest that there is a significant improvement in reliability indices when PV and battery energy storage are deployed at each home within a community. The presence of more than approximately 5 kWh of battery capacity per home reduced outage indices to nearly zero (almost a 100% reduction). The contribution of PV to the improvement in the reliability indices was less significant than was the contribution of a battery system, although enhanced reliability was still observed with significant PV penetration levels.

**The Future**
Successfully integrating a large capacity of PV systems into the existing power grid will require addressing several technical and policy issues.

Generation planning practices will need to evaluate generation flexibility with regard to the combined variability of the load and renewable resources. To support this, we will need solar resource data with higher fidelity (temporal and spatial).

To maintain current levels of transmission system reliability, IEEE 1547 and other standards should evolve to allow distributed resources to play an active role in distribution system operations and accommodate the increasing penetration levels of PV systems. The requirements for wind-power generation are a good starting point. Low-voltage ride-through, voltage and frequency regulation, and other grid code requirements should gradually be introduced into the technical requirements for PV inverters.

Deploying significant inverter capacity in distribution systems offers opportunities for better feeder voltage control and minimizing feeder losses. The infrastructure of the smart grid can be leveraged to implement coordinated operation of the distributed inverters and utility equipment, resulting in significant additional system benefits at low incremental costs.

Within the home, a combination of energy storage and PV may enhance the reliability of power supply in the event of an outage. In-home load-control technology can be deployed to enable the automatic supply of critical loads during an outage. Residential PV inverters can be used to manage the energy storage, and their operation can be coordinated with load control to provide home-scale energy management systems. (Our study examined the technical possibilities of these applications, but we did not address the economic viability of using storage for reliability enhancement relative to other alternatives.) By leveraging the infrastructure of the smart grid, these systems can then be aggregated to provide additional load flexibility to the greater grid.

**For Further Reading**


**Biographies**

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THE RACE TO BUILD THE SMART grid is on, with electric utilities across the country investing in both pilot programs and systemwide deployments of advanced digital technologies to manage generation, transmission, demand, and distributed energy resources in real time. Now, more than ever, the electric power industry must play an equally active and coordinated role in defining and developing the standards and protocols that will be needed to realize a secure and interoperable nationwide smart grid.

At a recent stakeholder workshop on smart grid interoperability standards sponsored by the National Institute of Standards and Technology (NIST), the electric utility industry accounted for less than 15% of the total attendance. If the industry continues to be severely underrepresented as the process moves to the various standards development organizations, the utility industry will have little say over the final standards as they are developed without its significant input.

When fully realized, smart grid standards have the potential to radically transform utility business models. They could dramatically change or alter the way that utilities produce, transmit, and deliver electricity. And the standards could conceivably redefine the relationships with, and roles of, the industry’s customers as well as create new business partnerships, new products, and new services.

The time for utilities to get involved is now, as the standard development initiative is moving very quickly. NIST has already released its interoperability framework and road map, which identifies 31 initial standards and 46 additional standards for further industry comment that will enable the vast number of interconnected devices and systems that will make up the nationwide smart grid to communicate and work with each other. The report also lists a set of 12 “priority action plans” that address important gaps identified by NIST.

To drive longer-term progress, NIST has established a Smart Grid Interoperability Panel. This public-private partnership will provide a more permanent organizational structure to support the ongoing evolution of the NIST framework. The panel also will assist NIST in identifying, prioritizing, and addressing new and emerging requirements for smart grid interoperability and security beyond the initial road map release. In 2010, NIST will develop and implement a framework for testing and certification of how standards are implemented in smart grid devices, systems, and processes.

Once NIST has certified the standards, the Federal Energy Regulatory Commission (FERC) will proceed with a rulemaking to adopt them. FERC issued a final smart-grid policy statement in July 2009 that addressed its jurisdictional authority, set priorities for work on developing the standards, and put in place an interim rate policy. Each of these actions will help to encourage and expedite investment in smart grid systems.

Electric utilities need to get more involved now as the standards development process moves from NIST to the many domestic and international standards development organizations, such as the National Electrical Manufacturers Association and IEEE, and eventually to FERC. Early and coordinated involvement is the only way to have a meaningful utility industry impact on the standards that are being developed.

Getting involved early in developing smart grid interoperability standards will help to avoid situations where the standards are formulated entirely by equipment manufacturers and technology vendors. This could create the risk that the standards do not reflect the industry’s operational concerns, and this could affect grid reliability.

Early and active participation in the process also will minimize the potential cost impacts on customers that could arise if utilities adopt technologies that later become obsolete or are found to be insufficient to meet minimum standards.

And finally, federal and state policy directives such as increasing demand response and energy efficiency and integrating renewable energy will be facilitated by the new standards. Since utilities will be charged with achieving these goals, they need to be actively involved in developing standards designed to enable or meet them.

For all of these reasons, it is critical that electric utility knowledge and vision are a part of the standard setting process. The smart grid represents a once-in-a-lifetime opportunity to renew and modernize one of the nation’s most important infrastructures. And electric utilities can ensure that all electricity customers—rural, urban, large, and small—benefit from the smart grid.

For more information about Edison Electric Institute’s involvement in the smart grid, please visit www.eei.org.
The IEEE Transactions on Sustainable Energy is intended to be a cross disciplinary and internationally archival journal aimed at disseminating results of research on sustainable energy that relates to, arises from, or deliberately influences energy generation, transmission, distribution and delivery. The journal will publish original research on theories and development on principles of sustainable energy technologies and systems. The Transactions will also welcome manuscripts on design, implementation and evaluation of power systems that are affected by sustainable energy. Surveys of existing work on sustainable energy may also be considered for publication when they propose a new viewpoint on history and a challenging perspective on the future of sustainable energy.

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