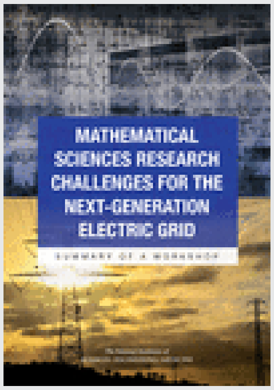

Mathematical Sciences Research Challenges for the Next-Generation Electric Grid: Summary of a Workshop

DETAILS

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MATHEMATICAL SCIENCES RESEARCH CHALLENGES FOR THE NEXT-GENERATION ELECTRIC GRID

SUMMARY OF A WORKSHOP

Michelle Schwalbe, *Rapporteur*

Committee on Analytical Research Foundations for the Next-Generation Electric Grid

Board on Mathematical Sciences and Their Applications

Division on Engineering and Physical Sciences

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This report has been reviewed in draft form by individuals chosen for their diverse perspectives and technical expertise, in accordance with procedures approved by the Report Review Committee. The purpose of this independent review is to provide candid and critical comments that will assist the institution in making its published report as sound as possible and to ensure that the report meets institutional standards for objectivity, evidence, and responsiveness to the study charge. The review comments and draft manuscript remain confidential to protect the integrity of the deliberative process. We wish to thank the following individuals for their review of this report:

Alejandro Aceves, Southern Methodist University,
Judith Cardell, Smith College,
Michael Chertkov, Los Alamos National Laboratory,
Clark Gellings, Electric Power Research Institute,
Peter Sauer, University of Illinois, Urbana-Champaign, and
Pravin Varaiya, University of California, Berkeley.

Although the reviewers listed above have provided many constructive comments and suggestions, they were not asked to endorse the views presented at the workshop, nor did they see the final draft of the workshop summary before its release. The review of this workshop summary was overseen by M. Granger Morgan, Carnegie Mellon University, who was responsible for making certain that an independent examination of this workshop summary was carried out in accordance with institutional procedures and that all review comments were carefully considered. Responsibility for the final content of this summary rests entirely with the author and the institution.

We also wish to thank National Academies of Sciences, Engineering, and Medicine staff Linda Casola and Elizabeth Euller for their help in preparing this summary.

Contents

1

Introduction

If the United States is to sustain its economic prosperity, quality of life, and global competitiveness, it must continue to have an abundance of secure, reliable, and affordable energy resources (DOE, 2015). In the case of electricity delivery, well-recognized challenges exist due to the increase in renewable energy sources, increase in consumer installation of distributed energy resources, greater system awareness (e.g., through smart meters and dynamic pricing), heterogeneities in the transmission system, and a technology space of new, useful tools that do not always interface well with each other (Overbye and Weber, 2001).

There have been many improvements in the technology and capability of the electric grid over the past several decades. New distributed sources of renewable energy are being integrated into the grid. New technology is improving stability and monitoring of disturbances, especially through the deployment of phasor measurement units that can report real-time information about the state of the grid and, in some cases, act to help stabilize the system (Sauer and Pai, 2007). New purchasing algorithms are assisting electricity transactions and enabling new (stochastic and intermittent) renewable energy sources to play a bigger role in the market. The connectivity of consumer leveraging information technology has improved.

Many of these advances to the grid depend on complex mathematical algorithms and techniques (Overbye, 2000). As the complexity of the grid has increased, the analytical demands have also increased. Developing a smarter next-generation grid is going to require novel system design and analyses that in turn depend on cutting-edge research in the mathematical sciences (Eto and Thomas, 2011).

WORKSHOP OVERVIEW

The workshop summarized in this report was developed as part of an ongoing study of the Committee on Analytical Research Foundations for the Next-Generation Electric Grid. The study and workshop were both supported by the Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE), which leads DOE's efforts to ensure a resilient, reliable, and flexible electricity system. The charge for the study is to identify critical areas of mathematical and computational research that must be addressed for the next-generation electric transmission and distribution system and to identify future needs and ways, if any, that current research efforts in these areas need to be adjusted or augmented. The study will also recommend how DOE can help build an appropriate multidisciplinary research community.

The workshop was an important means by which the study committee could gain additional insights to inform its work. That committee continues its work and plans to issue its final report early in 2016.

Accordingly, the study committee planned this workshop to involve experts from diverse communities, including mathematics, computation, and engineering, who could identify areas of inquiry where inroads by mathematical scientists could significantly advance the abilities of power systems engineers to analyze and control the electric grid. A subset of the study committee—consisting of Cynthia Rudin, Jeffery Dagle, Juan C. Meza, and Marija D. Ilic, and led by Robert J. Thomas—led the work of refining workshop topics, identifying speakers, and planning the workshop agenda. The workshop was held on February 11-12, 2015, at the Arnold and Mabel Beckman Center of the National Academies of Sciences, Engineering, and Medicine in Irvine, California. Approximately 65 participants, including speakers, members of the study committee, invited guests, and members of the public, participated in the 2-day workshop. The workshop was also webcast live. A complete statement of task is shown in Box 1.1.

This summary has been prepared by the workshop rapporteur as a factual summary of what occurred at the workshop. The study committee's role was limited to planning and convening the workshop. The views contained in the report are those of individual workshop participants and do not necessarily represent the views of all workshop participants, the study committee, or the Academies.

In addition to the workshop summary provided here, materials related to the workshop can be found online at the website of the Board on Mathematical Sciences and Their Applications (http://www.nas.edu/bmsa), including the agenda, speaker presentations, archived webcasts of the presentations and discussions, and other background materials.

BOX 1.1
Statement of Task

A public workshop will be organized and held as part of the information gathering for the Analytical Research Foundations for the Next-Generation Electric Grid study, addressing the following question:

What are the critical areas of mathematical and computational research that must be addressed for the next-generation electric system?

An individually authored summary report of this workshop, addressing only that portion of the Statement of Task, will be prepared and released mid-way through the study.

ORGANIZATION OF THIS WORKSHOP SUMMARY

Workshop presentations and discussions are summarized in subsequent chapters in sequential order. Chapter 2 sets the stage for current practice and future needs in electric grid research. Chapter 3 focuses on data and data analytics. Chapter 4 discusses optimization and control methods for a robust and resilient power grid. Chapter 5 focuses on uncertainty quantification and validation. Chapter 6 summarizes lessons learned and strategies moving forward from the workshop. Finally, Appendix A lists the registered workshop participants, Appendix B shows the workshop agenda, and Appendix C defines acronyms used in this report.

2

Setting the Stage

The first session of the workshop set the stage by discussing the history of the electric grid, the current and future sources of electricity generation, distribution and generation challenges, and key technologies that could help transition the current legacy grid into a grid structured to meet these future challenges.

Robert J. Thomas (Cornell University; chair of the workshop planning group), John Guckenheimer (Cornell University; study committee co-chair), and Thomas J. Overbye (University of Illinois, Urbana-Champaign; study committee co-chair) opened the workshop and introduced the speaker for the first session, former Department of Energy (DOE) Secretary Steven Chu (Stanford University).

LOW-COST PATHWAYS TO GRID INTEGRATION OF RENEWABLE ENERGY: SKATING TO WHERE THE PUCK IS GOING TO BE

Steven Chu, Stanford University

Steven Chu described how the energy landscape has changed rapidly over recent decades and outlined the importance of future improvements for the grid infrastructure and capabilities in the decades to come. He discussed some grid and consumer technologies that have the potential to improve the efficiency, reliability, and security of the electricity supply while also lessening emissions of greenhouse gases and improving human health.

Chu noted that until recently, petroleum production in the United States had been declining since about 1970. However, he said the introduction of hydraulic

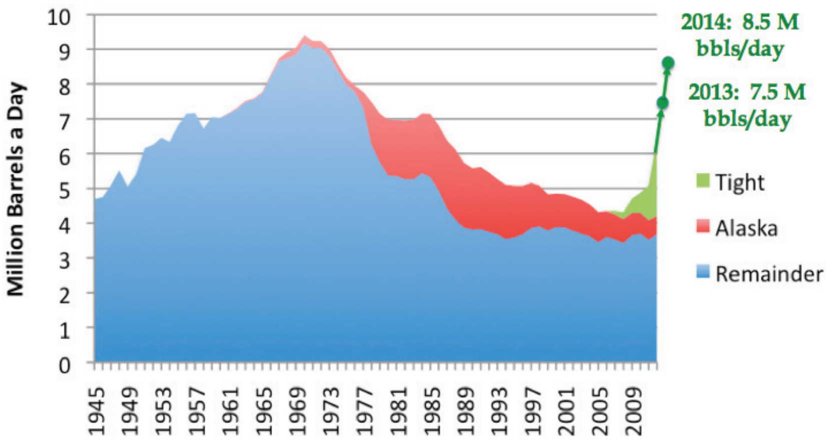


FIGURE 2.1 U.S. oil production since 1945. SOURCE: Steven Chu, Stanford University, presentation to the workshop; from Gail E. Tverberg, "Twelve Reasons Why Globalization is a Huge Problem," February 22, 2013, http://ourfiniteworld.com, based on Energy Information Administration data.

fracturing around 2005 led to a sudden increase in oil production that amounted to an additional 4.5 million barrels per day by 2014 (totaling approximately 8.5 million barrels per day overall), as shown in Figure 2.1. This production increase is more than the current oil production of all countries except Saudi Arabia, the United States, and Russia.

The U.S. Energy Information Administration (EIA), Chu noted, estimated that the rest of the world may have up to 10 times more tight oil[1] and shale gas than the United States. However, he warned there are great uncertainties in this estimate, and in fact, the amount of shale gas that is accessible globally may be only 30 to 40 percent of what is available in the United States. Figure 2.2 shows the EIA estimates for where, and how much, technically recoverable shale gas may be accessible.

Chu also discussed the environmental and human health implications of increased particulate matter, specifically a potential increased risk of lung cancer (Raaschou-Nielsen et al., 2013). He commented that the understanding of the risks of climate change is analogous to the understanding of smoking; notably, there was a delay in understanding the harms of smoking just as there was a delay in understanding the impacts of CO_2 on climate change. The damage to the environment from past CO_2 emissions will not be known for 50 to 100 years. Since CO_2 will remain for 300 to 3,000 years, Chu stated that a prudent risk management strategy calls for decreasing carbon emissions.

[1] Tight oil is defined as light crude oil within rock formations in low-permeable reservoirs.

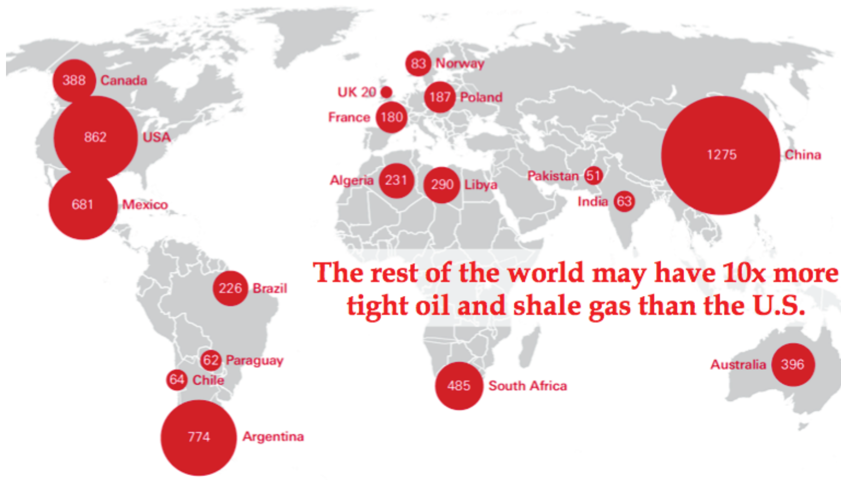


FIGURE 2.2 Estimates of global technically recoverable shale gas. SOURCE: Steven Chu, Stanford University, presentation to the workshop; from the Energy Information Administration, "Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States," June 13, 2013, http://www.eia.gov/analysis/studies/worldshalegas/.

What Are the Issues Facing Our Electric Grid?

Aged Transmission and Distribution Infrastructure

Chu commented that the United States has an aged transmission and distribution infrastructure architecture based on centralized, local generation. Ongoing challenges facing the grid include congestion, severe weather or other natural phenomena, and market and regulatory complexities. He noted that there are also new challenges, including intermittent renewables, cybersecurity, physical sabotage, and dynamic management of distributed generation.

The Northeast blackout of 2003 that cut off power to eight states in the United States and part of Canada, according to Chu, ultimately cost an estimated loss of $6 billion to $10 billion. He ascribed the blackout as being rooted in an out-of-date grid infrastructure. An electrical line disruption in northern Ohio resulted in a phase lag and led to one of the most massive blackouts in modern history. Chu said that faster real-time sensing and better grid control systems may have helped to prevent the resulting blackout.

The number of outages affecting more than 50,000 customers is also increasing, Chu said, reaching 349 during 2005 to 2009, up from 92 in 2001 to 2005, and 58 in 1996 to 2000 (NERC, 2009; EIA, 2009). He stated that many of these outages are a result of delayed maintenance and much of the infrastructure is past its designed life span.

Chu noted that DOE was given $34 billion in addition to its normal budget of $26 billion as part of the American Recovery and Reinvestment Act. Part of this money was spent deploying phasor measurement units (or synchrophasors) to provide fine-grained sensing of the state of the grid. He explained that these modern instruments can quickly spot oscillations in the grid and use systems that can provide reactive support, such as flexible alternating current transmission system (FACTS) devices. Oscillations were previously isolated using circuit breakers, but this approach can create strains in other lines as the amount of excess capacity in the grid has been squeezed.

Phasor measurement units measure the magnitude and the phase angle of the electric power signal time synchronized with GPS every 10 to 30 milliseconds, resulting in petabyte-scale data being generated. Chu noted that DOE began giving out these units in 2009, but as of 2012 utility companies were still not sharing the phasor measurement data with each other. A workshop participant noted that sharing has improved since that time, though.

Intermittent Renewable Energy

Chu stated that intermittent renewable energy, particularly wind and solar energy, will provide an increasing fraction of electricity generation in the future. This is good for the environment and difficult for the electric grid.

Wind turbines are increasing in reliability, efficiency, and size, and their prices are decreasing due to manufacturing economies of scale, according to Chu. Wind energy costs have plummeted dramatically since 1980, and the deployment of installed capacity has dramatically increased over the past decade, as shown in Figure 2.3. Chu noted that signed power purchase agreements (PPAs) for wind energy are a good indicator of where the industry is going. These PPA contracts define the commercial terms for the sale of electricity between two parties, including when a project will begin commercial operation, the schedule for delivery of electricity, the payment terms, and termination. He explained that the price agreed upon in a PPA is an indication of the market value for a type of electricity in a specific location and time. PPA prices tend to be highest in western states, such as California, and lowest in interior states, such as North and South Dakota, Iowa, and Kansas. However, he noted that PPA wind prices have been decreasing nationwide since 2009, as illustrated in Figure 2.4. Currently, the United States subsidizes wind energy through a wind production tax credit. However, Chu noted, owing to the current low prices in some geographic regions, the tax credit may not be essential nationwide. He suggested that determining whether or how to phase out the tax credit will be important to the future of the industry. Chu noted that the United

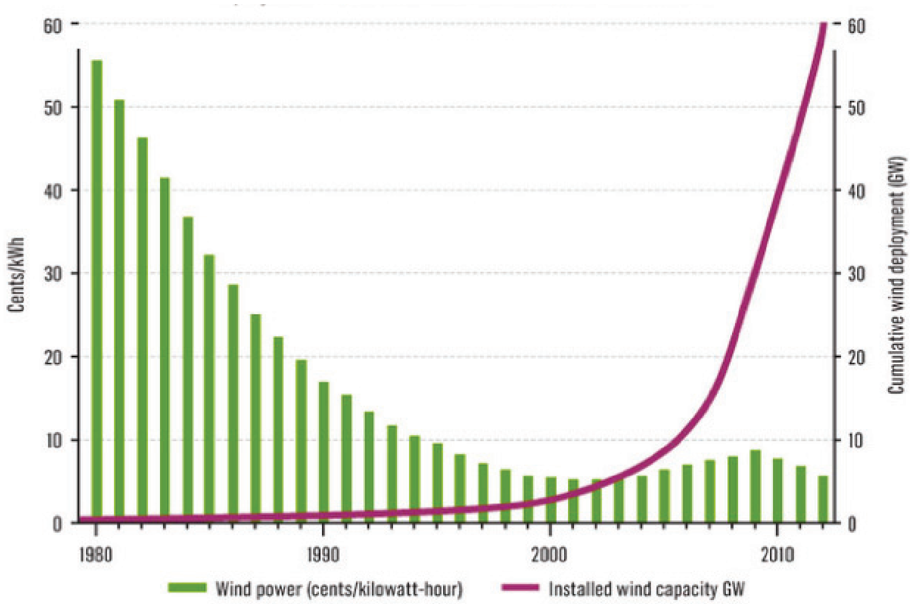


FIGURE 2.3 Wind energy costs and installed capacity from 1980 to 2012. SOURCE: Steven Chu, Stanford University, presentation to the workshop; from Department of Energy, "Revolution Now: The Future Arrives for Four Clean Energy Technologies," Washington, D.C., September 17, 2013, updated version available at http://energy.gov/eere/downloads/revolution-now-future-arrives-four-clean-energy-technologies-2014-update.

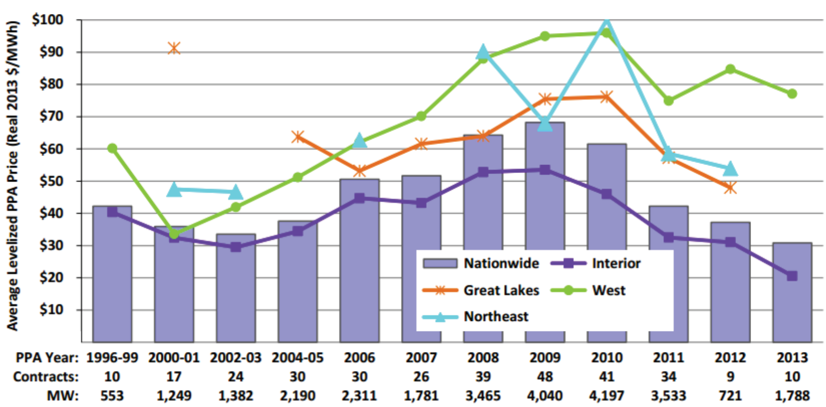


FIGURE 2.4 Time trends for wind power purchase agreements by geographic location from 1996 to 2013, adjusted for inflation and shown in 2013 dollars. SOURCE: Steven Chu, Stanford University, presentation to the workshop; from Wiser et al. (2014).

States is still lagging some other countries in wind electricity as a percentage of overall electricity consumption, even though the United States has extensive land resources. (The availability of land is key because offshore wind energy production is about three times more expensive than production on land.)

Chu said that solar energy is also becoming increasingly more viable as the cost of photovoltaic (PV) modules continues to decrease. Over the past 40 years, the price for PV modules has declined 40-fold. He noted that this rapid price drop, however, has led to some difficulties for some PV suppliers such as Solyndra and Suntech Power. Currently, utility-scale solar energy in Texas is comparable to the cost of new natural gas. Chu commented that the United States currently provides an investment tax credit of 30 percent, but he believes this could start ramping down to 10 percent in the next 6 to 10 years without disturbing the market. Solar electricity generation in the United States has skyrocketed since 2009, as shown in Figure 2.5. Chu said that DOE's loan program for solar and wind farms is paying off, and, even taking into account riskier loans (such as those to Solyndra and Fisker, which incurred losses), the United States is still estimated to net a $5 billion profit on its loan investments. However, in spite of this growth in solar energy capacity, he noted that this source still accounted for only 0.25 percent of all electricity generated in the United States in 2013. There is also great potential for solar power in developing countries, Chu noted, where solar modules and batteries can

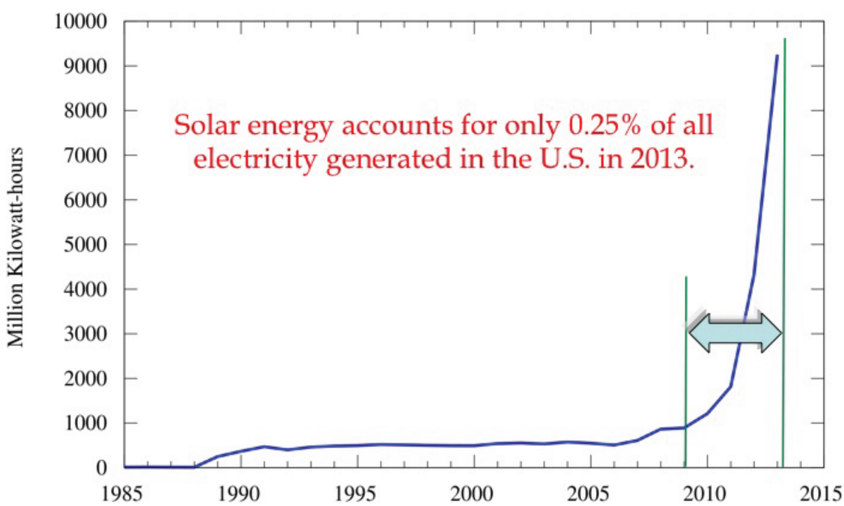


FIGURE 2.5 U.S. solar electricity generation from 1985 to 2013. SOURCE: Steven Chu, Stanford University, presentation to the workshop.

operate at a wide range of temperatures and provide inexpensive electricity for uses such as LED lighting, cell phones, refrigeration, and water purification.

Chu suggested that the renewable energy sector is about to change dramatically. He compared the natural gas, solar, and wind capacity additions in the first half of 2013 and 2014, which show increased investment in solar and wind, a high investment in natural gas, and no investment in coal. These investment amounts are shown in Figure 2.6.

Chu cautioned that the current electric grid, however, may have problems integrating these new renewable energy sources. The grid is made up of three major components (Figure 2.7): the Western Interconnection, the Eastern Interconnection, and the Texas Interconnection. Chu stated that the generation of electricity is not optimally distributed for the current grid; this is especially true for solar and wind energy. Because renewable energy is intermittent and can fade quickly, such as when the weather is cloudy or the wind stops blowing, the grid needs to be able to compensate when needed. Figure 2.8 shows the U.S. electricity generation sources and existing transmission lines, as well as new proposed transmission lines for solar and wind power.

While the U.S. grid is not designed to transport electricity long distances, Chu noted that high-power/high-voltage transistors can revolutionize high-voltage direct-current transmission lines and FACTS devices. Current long-range transmission is being addressed between European countries with the European high-voltage transmission grid and between provinces in China with China's national grid plans for 2020. Chu said that if the United States was to move to more high-voltage transmission, it could mean losing significantly fewer electrons per

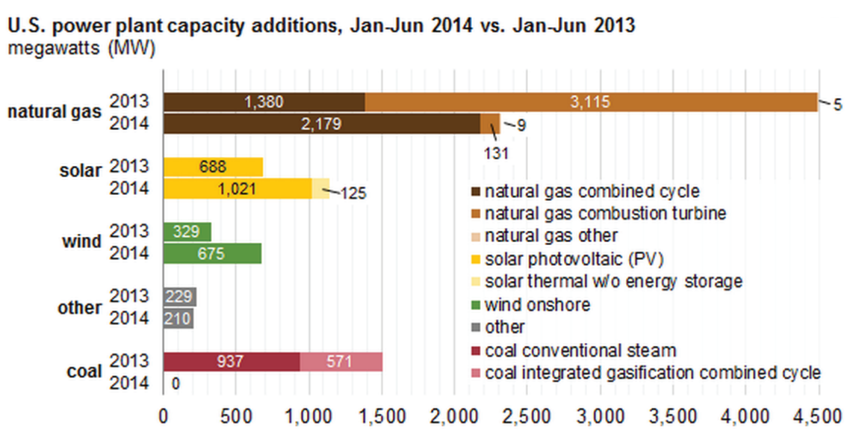


FIGURE 2.6 Natural gas, solar, and wind lead power plant capacity additions in the first half of 2014. SOURCE: Steven Chu, Stanford University, presentation to the workshop; from EIA (2014).

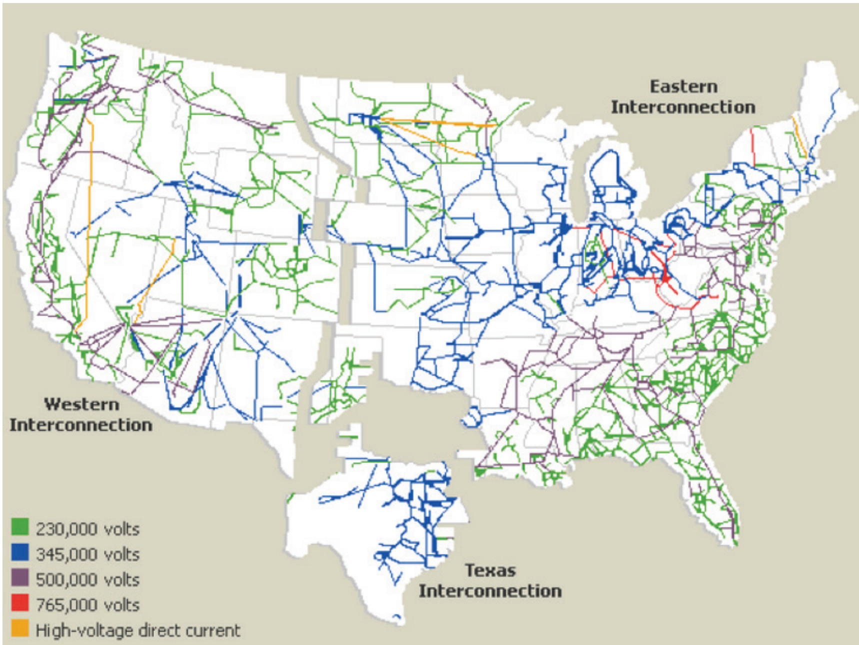


FIGURE 2.7 U.S. electric grid system. SOURCE: Steven Chu, Stanford University, presentation to the workshop; from Judith Curry, "Transmission planning: Wind and solar," *Climate Etc.*, May 7, 2015, http://judithcurry.com/2015/05/07/transmission-planning-wind-and-solar/.

kilometer traveled. There are current proposals for new 765-kilovolt long-distance transmission lines, Chu stated, but this proposal has been around for many years without much action or funding.

Cost of Distributed Generation

Chu stated that in some cases the cost of rooftop home solar generation is competitive with utility prices. Third-party solar installation—where a company creates a PPA with a household to install and maintain the company's solar panels and sell the generated solar power for a fixed number of years, often at no up-front cost to the household—can result in the consumer receiving electricity at a kilowatt-hour price that is lower than what is available through a utility company. Chu expects that consumers will increasingly participate in these third-party solar installations, which will result in a decreased need for energy during peak solar production times (usually noon to 4 p.m.) and an increased need for more electricity as the solar power fades in the evening.

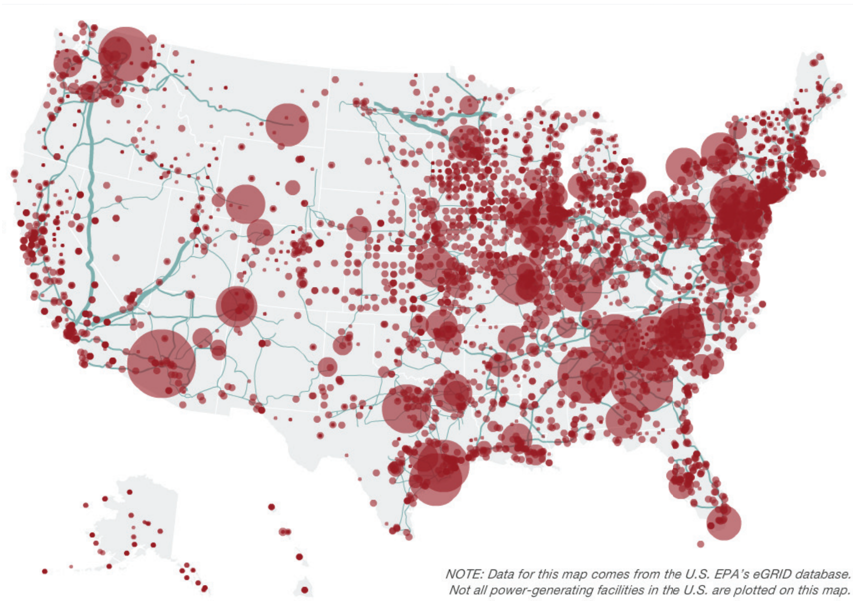
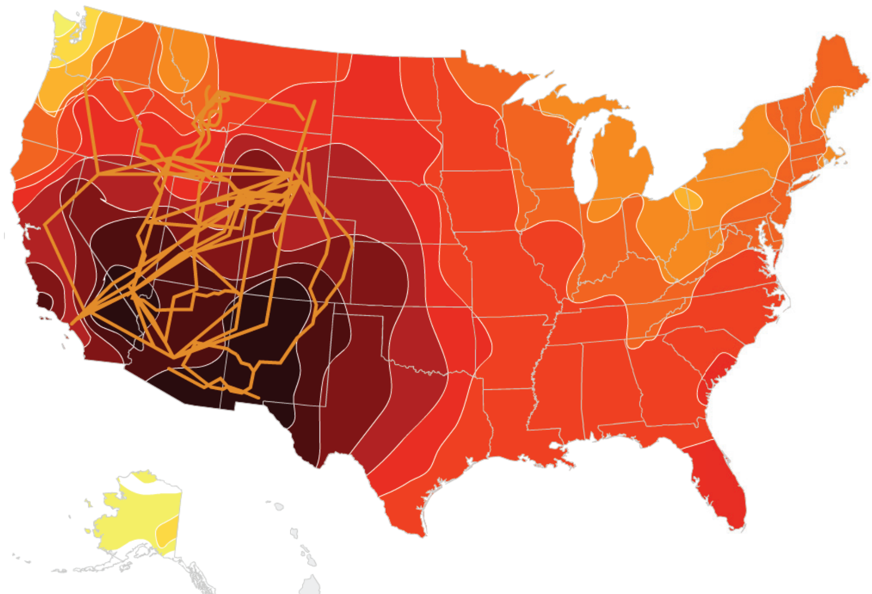
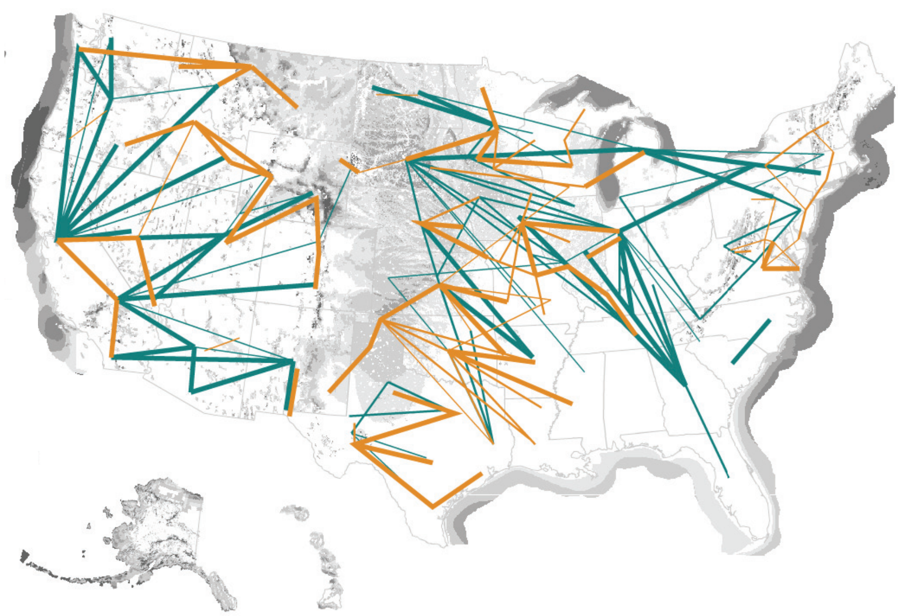


FIGURE 2.8 U.S. electricity generation sources and existing transmission lines (*top*); U.S. solar power capacity and proposed transmission lines (*top of next page*); and proposed wind transmission lines (*bottom of next page*). SOURCE: Steven Chu, Stanford University, presentation to the workshop; from National Public Radio, "Visualizing the U.S. Electric Grid," April 24, 2009, http://www.npr.org/2009/04/24/110997398/visualizing-the-u-s-electric-grid. Source: American Electric Power, American Wind Energy Association, Center for American Progress, Department of Energy, Edison Electric Institute, Energy Information Administration, Electric Power Research Institute, Federal Energy Regulatory Commission, National Renewable Energy Laboratory, U.S. Environmental Protection Agency, Western Resource Advocates. Credit: Producer: Andrew Prince; Designer: Alyson Hurt; Editors: Avie Schneider and Vikki Valentine; Supervising Editors: Anne Gudenkauf and Quinn O'Toole; Additional Research: Jenny Gold; Database and GIS Analysis: Robert Benincasa.





Many municipal and institutional organizations have become their own power stations as well, Chu noted. For example, the Texas Medical Center has a combined heat and power system capable of producing 48 megawatts of on-site generation, with 32,000 tons of chilled water capacity and an 8.8-million-gallon thermal energy storage tank. Stanford University is currently building a similar power plant.

Electric Vehicles and Consumer Energy Storage

Electric vehicles and consumer energy storage add further complications to the grid, Chu said, and may become a problem once electric vehicles are widely used. He believes that current electric vehicle deployment is slow in part because battery prices, while dropping, continue to remain high. He noted that there has been significant progress in battery research and development, although it does take 4 to 5 years to develop new automotive batteries, in large part because of extensive safety testing; he believes that innovative battery chemistries will likely be widespread in the near future.

New Business Models and Regulations Are Needed

As technology changes the paradigm of the grid, Chu said, new business models and regulations are needed. He explained that utility companies are becoming distributors that aggregate power mostly through day-ahead bidding—with approximately 90 to 95 percent of electricity being purchased this way—with fewer long-term contracts. Utilities aggregate from natural gas, coal, nuclear, solar, and wind, but typically only nuclear power will have a long-term contract in place. In many geographic areas, the independent system operator (ISO) processes the bids and feeds the information to the utility company. In addition to the long-term contracts and the day-ahead market, Chu explained, there are mechanisms to fill gaps in electricity needs and provide stability across minutes, seconds, and sub-seconds throughout the grid. However, he noted, the day-ahead market for renewable energy is challenging because it is difficult to predict generation in advance. He said that deeper penetration of renewable sources may require adjustments by energy regulators, utility companies, and ISOs. In particular, Chu emphasized, more 1-hour and 15-minute bidding may allow renewables to compete more effectively.

Other changes in sensors, load prediction (via machine learning) and control, and better forecasting and dynamic demand response could help modernize the grid, in Chu's estimation. Forecasting of renewable energy is improving. Utility companies often aggregate power generation from merchant providers of energy, and, Chu said, they also should be able to aggregate consumers who would sign up to allow the utility company to modify their thermostats, electric hot water heater, and other high-energy-use devices. He said that various predictive models have been developed for distribution load forecasting, including stochastic time-series models.[2]

The current paradigm was described briefly by Chu as follows. The ISOs balance the electricity supply and demand using day-ahead, hour-ahead, and 15-minute-ahead pricing and then schedule the needed electricity to the utility company. The utility company distributes the electricity to consumers on a pre-defined price structure, such as the Tiers 1-4 in California, that have an increasing kilowatt-hour price. Typically, the wholesale price of electricity is less than half of what utility companies charge consumers per kilowatt-hour. This system allows for utility companies to pay for transmission and distribution, to earn a profit, and to create a stable system.

However, Chu said, this system is changing. As noted above, a customer's own solar panels might provide electricity at a kilowatt-hour price below what the utility company can charge. The home could then return or sell its unused electricity to the grid, although the details of this exchange need to be established. As electric vehicles become more commonplace over the next decade and prices for stationary batteries with larger capacities decrease, Chu observed that consumers may opt to use solar power to charge their own stationary battery and power their electric vehicle. He said that consumers may also utilize a gas utility to power a personal electricity generator, the waste heat of which can provide hot water. This scenario will result in generation from many sources (centralized baseload such as coal and gas and intermittent renewables such as solar and wind), with centralized storage and distributed intermittent generation, local storage, and load all being connected by a legacy grid that was not designed to handle such a complex system. Both the current and the shifting paradigms are shown in Figure 2.9.

Solar and battery technology for both vehicles and stationary storage could be disruptive to electricity generation and distribution, according to Chu, but utility companies are not focused on transitioning to the low-cost option of utilizing these technologies. The main reason, he suspects, is that utilities are monopolies and may not have proper incentives to innovate and adopt new technologies. Chu recommended that utility companies work with regulators to upgrade infrastructure to better integrate renewable energy. For example, he proposed the following solution to align utility company incentives with deployment of solar energy: offer consumers rooftop electricity and in-home energy storage where distribution companies partner with third-party installers so that distributed generation and storage is owned, installed, and maintained by energy providers.

[2] Some of these stochastic time-series models include the autoregressive model, autoregressive moving average model, autoregressive integrated moving average model, and other models using fuzzy logic and neural networks.

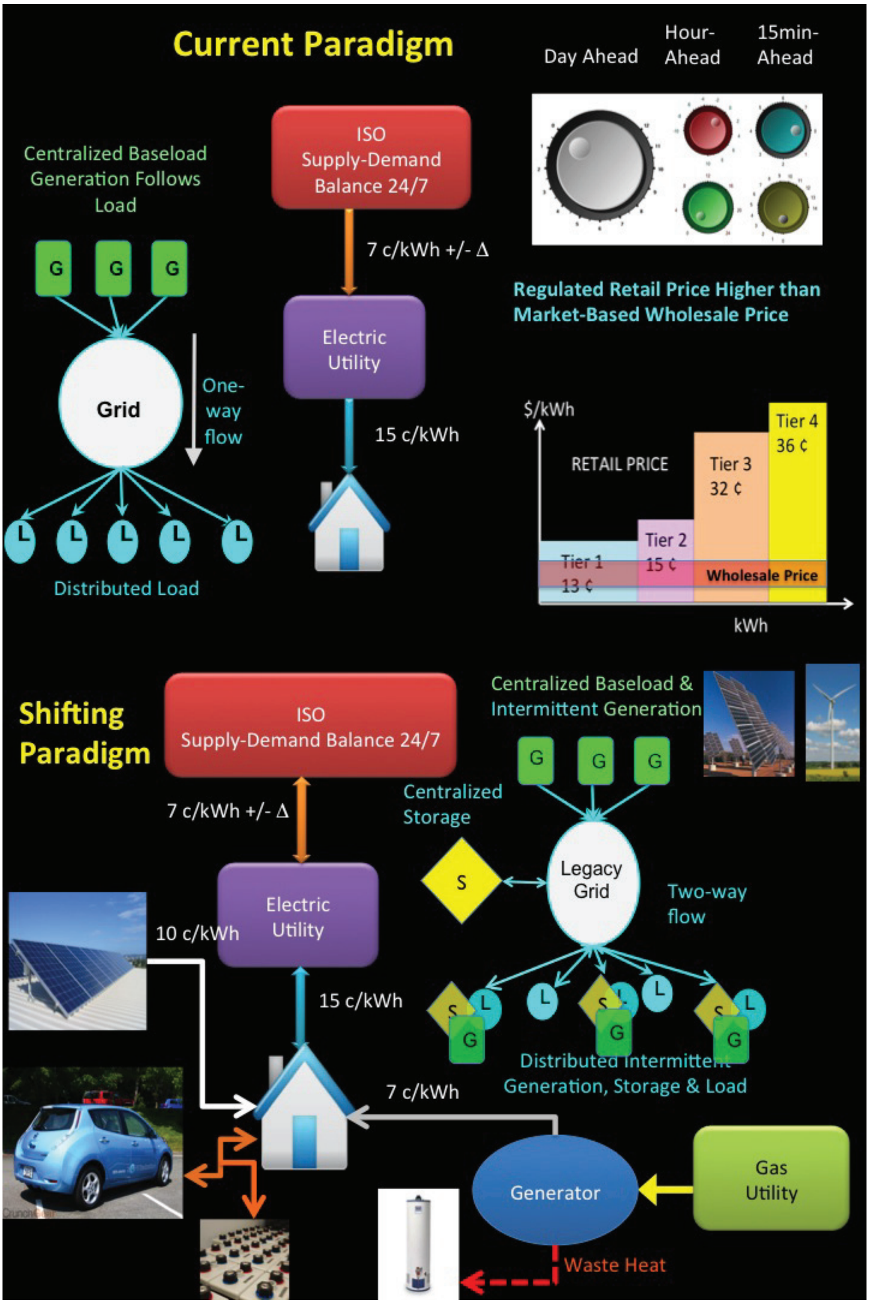


FIGURE 2.9 Current (*top*) and shifting (*bottom*) energy paradigm. SOURCE: Steven Chu, Stanford University, presentation to the workshop; courtesy of Arun Majumdar.

Chu said that the country needs new regulations and new business models for the grid. He listed the following five key components to grid modernization:

- *Renewable integration:* variability and intermittence,
- *Energy storage:* regulation and load shaping,
- *Load management:* peak load shedding,
- *System operation:* coordination from the national to the nanoscale, and
- *Cybersecurity and physical security:* securing the physical infrastructure and two-way communication.

Chu described the reliability coordinator networks throughout the country that monitor the interconnected transmission system and take immediate action if needed. This monitoring depends on an information infrastructure that is in need of improved sensing capabilities (via phasor measurement units), improved communications (via grid connected routers that can automate and control local portions of the grid), and improved computation (via distributed cloud computing that can provide fast, secure, and resilient computing capabilities).

Moving to a smart grid has many potential advantages, according to Chu, including the following:

- It could transfer electrical energy from areas where it is cheap to those where it is expensive.
- It would optimize assets and enhance reliability while sharing the cost of redundancy.
- It would accommodate all generation and storage options.
- It would be self-healing and resistant to cyber and physical attacks.
- It would motivate and include the consumer.
- It would provide power quality at the levels needed.

Chu concluded by adding that one key research area for government investment is research in wide-band-gap materials to make diamond, silicon carbide, gallium nitride, and boron nitride transistors. He said that utility companies are not going to invest in this research and development, but the availability of these types of transistors would facilitate the development of key smart grid technologies.

3

Data and Data Analytics

The second session of the workshop provided an overview of the latest research to improve sources of data and methods of data analytics for the next-generation electric grid. The session was co-chaired by Cynthia Rudin (Massachusetts Institute of Technology) and Marija D. Ilic (Carnegie Mellon University). Presentations were made in this session by David Sun (Alstom), Louis Wehenkel (University of Liege, Belgium), and Matthew Gardner (Dominion Virginia Power).

PROSUMER-CENTRIC POWER INDUSTRY TRANSFORMATION

David Sun, Alstom

David Sun began by explaining that his presentation would characterize the U.S. electric grid today and suggest where it should aim to be in the future. He expects that the future will involve changing the way companies and utilities think about their business, the way technology is used, and the way utilities work with other partners. Sun noted that the energy ecosystem is changing: loads now change rapidly and require flexibility, and the notion of cost-benefit trade-offs is evolving. These challenges are business opportunities.

Sun said that the power system industry has changed dramatically in recent years, and it is currently strong, resilient, and reliable. The 1980s classic utility was vertically integrated with a cost-based operation and its own physical infrastructure. In the 1990s, competition was introduced into the utility industry by opening transmission access and creating wholesale electrical markets. He said the era of the smart grid began in the 2000s with distributed intelligence, service valuation, and prosumer[1] choices. Technology has given consumers new choices about electricity consumption and generation, and this is forcing utilities to be more sensitive to consumer demands. Sun sees the future as interconnected cities with increased sustainability, resiliency, and connectivity.

The market evolution from a regulated and vertically integrated system to a wholesale deregulated system, Sun explained, came about in two ways: an energy-centric evolution and a transmission-centric evolution. Neither path of managing the electrons or the transmission lines, respectively, worked independently, but eventually both paths merged to create a balanced converged-market model.

Sun described security-constrained unit commitment-based optimization as an example of an important evolution within the independent system operators (ISOs). A couple of decades ago, he explained, operators used fixed priority orders for unit start-up and shutdown. This evolved into dynamic priority order and, in 1996, the standard became dynamic priority order sequential bidding. Enhanced Lagrangian relaxation was introduced in 2001 to support this optimization, and mixed-integer programming came into play in 2003. In 2013, market optimization benefited from AIMMS 3.13 (Advanced Interactive Multidimensional Modeling System, a software package designed to model and solve large-scale optimization and scheduling problems) and CPLEX 12.5 (an optimization software package accessible through AIMMS). Sun said that the current state-of-the-art approach is mixed-integer programming with meta-heuristic and stochastic optimization. According to Sun, this continued evolution has improved reliability, lowered expenses, and lowered uplift payments; the current annual cost savings attributed to this optimization exceeds $90 million.

Sun noted that many decisions are made on different timescales in wholesale generation markets. He stressed that a lot of experience and judgment are involved in these decisions, and various business processes need to be leveraged to have a smooth progression of decisions in order to optimize electricity supply. These decisions are always being reviewed and reconsidered to make the system better. The ISO needs to look at its long-run and day-ahead purchases and then try to fill in the gaps with short-term and quick-turnaround electricity sources, Sun said. When there is intermittent uncertainty, there needs to be some flexibility at the end of the purchasing line so that gaps can be filled. This is a complex system with more than 1,000 generators used over the course of 24 hours. The measured data and mathematical analyses provide important input to good decision making, but Sun stressed that they cannot answer all the business questions that arise. He said that what is needed is a multidisciplinary approach involving control theory,

[1] The term "prosumer" typically describes the market segment with characteristics of both professional and consumer.

mathematics, data analytics, human factors, and business. As a new generation of ecosystem stakeholders takes on the smart grid, Sun views it as essential that the economic return on investments be considered. For example, Sun argued, while the technologies for batteries and photovoltaics are improving, the evolving business paradigm for employing those technologies needs to be addressed.

Moving to a smarter grid allows many decisions to be decentralized, which Sun believes may end up better serving customers. Pilot smart grid projects are happening all over the world. One example he discussed is the Pacific Northwest Demonstration Project, a 5-year project covering 60,000 metered customers in Washington, Oregon, Idaho, Montana, and Wyoming. This $178 million DOE-funded smart grid project is led by the Pacific Northwest National Laboratory and includes collaborators such as Alstom, IBM, the Bonneville Power Administration, 11 utilities, the University of Washington, and Washington State University. Sun explained that the project goals are to quantify the costs and benefits, develop communications protocols, develop standards, and facilitate integration of wind and other renewables.

Another demonstration project Sun discussed is the NiceGrid Secondary Flexibility Markets being set up in the southeast region of France. He noted that this region is challenging because the area requires stable electricity, yet the transmission corridor is at risk of forest fires. The region would also like to increase solar power sources. According to Sun, the demonstration project will bring together electricity distribution companies, wholesale companies, and distributed energy resources—including distributed components such as energy generation, demand response, and energy storage. The essential goal is to connect end customers with ISOs.

Sun said the current business proposition for grid-connected energy storage resources is not good, but he described several revenue opportunities that could reflect the true value of this service:

- Capacity-resource revenue, which is the analogue of revenue for generation capacity;
- Capacity-connection charge reduction to reduce maximum connected demand;
- Emergency curtailment revenue to reduce net demand during emergency events;
- Energy price arbitrage across time (real-time pricing), including the price differential between high/low price intervals;
- Ancillary service (regulation service) to address capacity payment for up/down regulation capacity; and
- Ancillary services (reserve capacity) operating and/or replacing reserve capacity payment.

The system is currently bundled, but Sun expects services to be unbundled due to new services in the future.

Sun stated that current optimization applications have gained acceptance and perform critical functions in control center operations such as the bulk power grid, wholesale market, and distribution grid. He said there is an unrelenting demand for faster and smarter solutions to optimization problems. The path from research to deployment starts with conceptualizing the business problem, followed by formulating a mathematical model, preparing data, developing a solver engine, and eventually assessing a solution. There can be a big gap between any of these steps, Sun cautioned. This pathway is shown in Figure 3.1.

Sun proposed the following research and development directions:

- Methods to help evaluate expanded business requirements
  - Risk-based decision making
  - Multilevel and distributed decision making, such as coordination and aggregation
  - Analysis of cross-domain interdependence of gas-electric coordination, water, etc.
- Improved analytical solution technology
  - Mixed-integer programming: hot-start, heuristics
  - Stochastic/robust optimization
  - Post-solution assessment and recommendations
- Data and data management
  - Methods suitable for heterogeneous data
  - Methods for data transformation
  - Visual analytics
  - High-performance computing

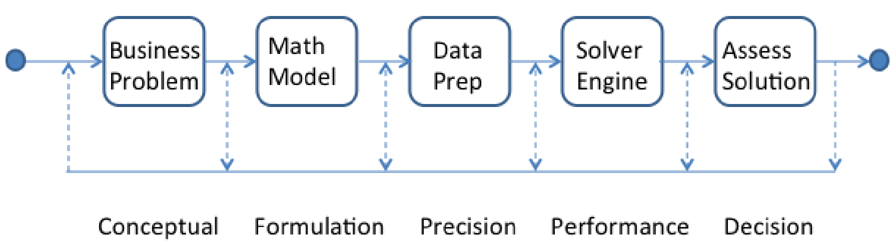


FIGURE 3.1 Pathway from research to deployment of practical optimization. SOURCE: David Sun, Alstom, presentation to the workshop; copyright 2015 Alstom Grid.

HOW TO COMBINE OBSERVATIONAL DATA SOURCES WITH FIRST PRINCIPLES OF PHYSICS TO BUILD STABLE AND TRANSPORTABLE MODELS FOR POWER SYSTEM DESIGN AND CONTROL

Louis Wehenkel, University of Liege, Belgium

Louis Wehenkel explained that his presentation would center on the electric power transmission system while addressing modeling issues from the viewpoint of the transmission system operator. These operators own the transmission grid and are responsible for operating it. While Wehenkel did not discuss it much in his presentation, he stressed that data visualization is important to modeling and understanding data.

The electric power system, as defined by Wehenkel, is closely coupled to consumers, producers, markets, and suppliers and is influenced by the rest of society, the economy, the weather, and environmental factors. He explained that the system is designed and controlled by a team of transmission system and distribution system operators, and it is overseen by regulators.

Wehenkel described three different types of grid-related decision making that must be informed by models:

- *Grid (re)design.* Design and redesign are called for when new technologies and/or new demands arise. Related decisions support the planning of grid expansions and equipment modifications, perhaps to create a more agile system that can adapt to changes that may come. This decision making deals with longer terms and uncertain projections.
- *Asset management.* These decision-making activities address how best to manage an aging infrastructure that cannot be "rebooted" or rebuilt from scratch. There is a need for better modeling of equipment aging processes and a more effective prioritization of maintenance, taking into account the condition of pieces of equipment and their criticality to the system.
- *Operation and control.* The dynamic behavior of the distribution system is rapidly evolving, with more uncertainty and new dynamics as the components of the system evolve, and this poses new requirements on control models. Industry should work toward developing probabilistic and/or robust optimization methods that exploit more measurements and use better algorithms.

How Can Data and Data Analytics Help?

Models can be split into two types, according to Wehenkel: statistical models based on observational data and physical models created from first principles.

He explained that the statistical models are typically representations of joint or conditional probability densities over a set of random variables, induced from observational data. They may include Gaussian processes, Markov chains or fields, logistic models, random forests, and support vector machines. The physical models are often representations of deterministic constraints among physical quantities that describe a system, such as algebraic and differential equations obtained from first principles. Most electric power system models are a combination of these two types, according to Wehenkel.

Models are used, Wehenkel explained, to describe testable hypotheses about real-world behavior and to understand and communicate knowledge about the real world. Models can also be used to figure out what kinds of experiments would provide information necessary for understanding system behaviors. Wehenkel said that models enable one to answer three types of inference questions:

- *Observational questions:* What might one observe about the grid when certain conditions are seen? For example, what is the probability of a blackout, given that weather conditions are bad?
- *Action questions:* What if a particular action is done? For example, what would the probability of a blackout be if some load was curtailed?
- *Counterfactual questions:* What if things had been done differently? For example, would there have been a 2003 blackout if the computers at FirstEnergy and the Midcontinent ISO had been working correctly?

Other desirable properties of models, according to Wehenkel, include simplicity (easy to understand, no superfluous parts), falsifiability (possible to verify through experiments), tractability (can be exploited efficiently), modularity (can be combined with other models), scalability (can be used in the real world), stability (can be updated smoothly over time), and transportability (can be used in different contexts).

What Kinds of Research Efforts Are Needed?

Wehenkel observed that several areas of grid modeling need more focus, including models of the environment, of socioeconomic factors, and of physics of the power system. For the environment, he said, better modeling is needed of the impacts of weather and the climate on generation and grid subsystems and on end users. An example he mentioned would be connecting wind and cloud forecasts with projections about renewable energy availability, loads, and outage patterns. For socioeconomic factors, better modeling is needed of the behavior and preferences of end users, markets, and societies, such as demand-side and market response. For power system physics, the community needs to better understand the behavior of components and to refresh or revisit dynamic system models, such as aging and failure modes of devices and dynamics of distribution subsystems.

In most of these cases, Wehenkel stated, the available data come as a mixture of large sets of internal and external data and pure observational data and information about physical structure. He noted that the aspects to be modeled are typically coupled. There may be some confounding by weather or by other external factors, and there is a need to model the spatio-temporal correlations among load, generation, faults, and other disturbances. Sometimes, Wehenkel stated, there is a lack of appropriate data due to the rare nature of some extreme events and to data "censoring" as a result of past and current policies with regard to sharing data on system operations and maintenance.

Wehenkel said that the industry needs forecasting that can estimate not only conditional expectations of future values, but also, in order to quantify uncertainty, the conditional distributions associated with those values. He explained that these estimates are needed for accurate risk assessment analyses and decision making. Weather conditions are one of the main influencing factors he described, and they yield correlations among load, generation, and outage rates, both in space and in time. Given that there may be thousands of variables, Wehenkel said, it can be difficult to build tractable models from available data with multiple time steps and correlations. The statistical dependencies in the variables can be difficult to model. Wehenkel suggested building on sparse or hierarchical models, tree-structured graphs, or chordal graphs. These approaches have minimal complexity while still being able to model correlations between variables, and they support learning and inference.

Wehenkel stated that better modeling of loads and demand is also needed; specifically, better dynamic models that respond to voltage/frequency variations over shorter time periods (seconds and minutes) are needed for stability analysis. He said better estimation of the value of lost load (i.e., end-user utility functions) is needed to formulate probabilistic reliability management criteria. He suggested that industry consider the possibilities of novel data acquisition channels together with optimal experiment design to enable demand-side response. This approach might include active learning and reinforcement learning approaches. He noted that distribution and collaboration between transmission system operators is necessary for such an effort to move forward.

Wehenkel also gave two examples of problems for which data are scarce: the estimation of the remaining lifetime of transmission system assets and the estimation of joint probabilities of multiple faults. Both of these estimates are needed in order to develop risk-based reliability management strategies. He said these topics are currently under investigation, in the context of the European Commission's collaborative research and development project GARPUR.[2]

In order to develop reliability-centered maintenance, Wehenkel said, both the health state of grid assets and their criticality need to be quantified. He referred to this as the "remaining lifetime assessment," and he noted that the health condition of a given device depends on its history of stress (climate based, flow based, and on/off cycles) and on past maintenance operations. Equipment often comes in technology groups (such as groups of transformers of the same generation), Wehenkel commented, but individual elements may age differently. In transmission systems, he said that past maintenance policies have been such that very little, if any, equipment goes into a "terminal" state. This means that the models may lack data about the failure of elements, which can make modeling the aging process more difficult. If there were better models, Wehenkel believes maintenance strategies could be improved to increase system reliability at a lower cost.

Wehenkel posited that solving this problem requires a combination of physical models of degradation processes along with additional experimental data and ad hoc statistical estimation. He encouraged more data- and experience-sharing among transmission service operators. He noted that the same problem also exists in distribution systems, but data about real failures are more common for those systems. He speculated that some distribution models could be applied to transmission systems.

Another data-limited problem discussed by Wehenkel is estimating the probabilities of "N – k events," which are the probabilities of the different kinds of threats (such as outages) possible within the system. These can be multiple events in some cases, he explained, such as multiple outages in harsh weather conditions. The probabilities of different events and combinations of events change in time and space. To focus attention on the most useful subset of events, Wehenkel said that rough estimates of probabilities are needed. But these can be very difficult to estimate, even for incidences of single outages, due to weather conditions and equipment health-state. Wehenkel commented that it is even more difficult to determine under which conditions individual events may be treated as independent (conditionally on the weather and the health-states) and, if not, how to quantify the joint probabilities of multiple events. He stated that it may be necessary to consider two, three, or even more events jointly to assess the actual threats correctly.

Wehenkel suggested that machine learning can be used to build proxies to inform the system. He said that models that can accurately simulate detailed real-time operations are typically in the form of some (maybe stochastic) formulation

[2] See the GARPUR (Generally Accepted Reliability Principle with Uncertainty Modelling and through Probabilistic Risk Assessment) website at http://www.garpur-project.eu (accessed July 24, 2015).

combined with some algorithmic solution heuristics. When taking day-ahead decisions, he said, operation planners need to estimate next-day real-time operation over many possible scenarios and over many different time steps. This means that day-ahead decision making carries the complexity of real-time decision making raised by several orders of magnitude. When moving to asset management and further to system planning, Wehenkel noted that optimization horizons of one to several years are discussed, which obviously raises complexity by several orders of magnitude. Wehenkel's notion is that a simple function might be able to mimic what is happening in real time. This "proxy" would be a function whose input is a representation of the information state used in real-time operation and whose output is an estimate of the result of the real-time decision-making process. In principle, he said, such proxies could be built by using state-of-the-art machine-learning algorithms combined with Monte Carlo simulation and optimization tools. If a good proxy is obtained, Wehenkel said, it could be used a day ahead in place of the cumbersome, detailed, real-time decision-making model. Similarly, he said, a proxy for day-ahead decision making may be built for use over longer horizons for decisions related to asset management or system planning. Such a day-ahead proxy would also integrate the effects modeled by the real-time proxy.

Wehenkel believes that transmission service operators could share such proxies and allow one another to take into account information they need from other geographic areas when making decisions, leading to some sort of horizontal coordination. Transmission and distribution service operators could share such proxies, leading to some kind of vertical coordination. Wehenkel said that such ideas are currently under investigation in the context of the European Commission's project iTesla.[3]

Wehenkel concluded by highlighting the need for causal models beyond those that can be provided by pure statistics. Such models would need to blend physics and statistics in the proper way. He stressed the need to integrate modeling, simulation, and control into a single overarching activity. In this context, causal models may help to guide the trade-off between exploration and exploitation. Lastly, he reiterated that machine learning might be used to build tractable proxies of subsystems and of subtasks, with the latter possibly reused in many different contexts. Wehenkel suggested Pearl (2009) and Schweppe (1978) as additional reading.

Proxies were revisited during a later breakout session during which a participant stressed that these are the key mathematical challenges. More specifically, the challenge is how to analyze the multigranularity aggregation in a rigorous way. The ongoing DYMONDS activity at Carnegie Mellon University was mentioned as a project that is addressing this challenge.

[3] iTesla, "Innovative Tools for Electrical System Security within Large Areas," accessed July 24, 2015, http://www.itesla-project.eu/.

GRID-SCALE DATA FUSION: OBSTACLES AND OPPORTUNITIES

Matthew Gardner, Dominion Virginia Power

Matthew Gardner began his talk by discussing synchrophasors, which are phasor measurement unit (PMU) devices that measure the electrical sine waves on an electricity grid and have the capability of putting a time stamp on each measurement. He said that synchrophasors give real-time data about electrical disturbances populating across the grid, and such data show, for example, that it can take multiple seconds for disturbances to travel across the country.

Dominion Virginia Power deployed synchrophasors across their extra-high-voltage network using stand-alone and dual-use PMUs, according to Gardner. The dual-use PMUs are integrated into protection and control equipment, while the stand-alone PMUs are utilized in sensitive areas where control is not desired. Gardner explained that the synchrophasor rollout was initiated with DOE funding, and Dominion was able to install 38 control houses and more than 20 stations. He said additional PMU deployment then became standard business for the company, which deployed additional PMUs in more than 35 locations over the first year. These PMUs capture three-phase voltages, three-phase currents, frequencies, and breaker status for each relay/PMU deployed and all transmission voltage levels covered (500 kV, 230 kV, 115 kV). Dominion uses dual-use relay PMUs wherever possible, Gardner said. He recommended that power companies take advantage of scheduled replacements to deploy relays with PMU capabilities. He noted that the equipment is standard and widely used in utilities. However, he stated, output data are not standardized across manufacturers, and this creates a problem in dealing with data dimensionality.

PMU deployment has dramatically increased across the country over the past decade, which Gardner believes was sparked by the Northeast Blackout of 2003 and by early adoption by progressive organizations. With this widespread deployment, interoperability is a concern. Gardner highlighted three key challenges for interoperability:

- *Standards.* Conformance to standards must be achieved as a precursor for interoperability, but conformance alone is not enough.
- *Testing.* Consistent testing and conformance assessment can verify performance and potentially interoperability and is key to consistent interpretation of test results. Testing can also identify the need for improvements to devices and systems, as well as provide feedback for improving standards and implementation agreements. However, both standards and implementation agreements are subject to interpretation and may allow for disparate options, choices, or configurations.

- *Life-cycle management.* Life-cycle management, asset utilization, and revision control are all considerations affected by interoperability. Architecture interoperability needs to support system life-cycle management and asset utilization (long-term system deployment roadmap).

Data quality is also an important issue, according to Gardner, especially as PMU deployments have grown in size, shape, and number. Organizations are now trying to extract value from their investments by "operationalizing" their data in energy management systems, in special PMU data visualizations, in situational awareness and other special PMU applications, and in engineering roles such as planning and equipment engineering. However, he said, many are experiencing difficulties due to quality of the synchrophasor data.

Gardner said that a number of data-quality myths and misconceptions need to be corrected, such as the incorrect notions that companies can just plug in synchrophasors and receive reliable data and that all types of synchrophasors are equally accurate. He stressed that existing applications are not robust enough to handle bad data quality.

Gardner explained that a variety of data-quality issues develop from many conditions, including dropouts or packet loss, latency, repeated values, measurement bias, bad or missing time stamps, loss of GPS synchronization, incorrect signal meta data, planned or unplanned outages, poor server performance, and improper device configurations. He said that many of these data-quality issues could be solved or mitigated by basic steps such as checking data on frequency, voltage, and current to see if the reported values are near what is expected for the system. Dominion is pushing to automate much of this initial checking, although Gardner does not believe this is common across the industry.

PMUs are an important component in power system metering technology, but they cannot provide accurate and meaningful results on their own, Gardner said. Proper functioning requires precise placement of devices for optimal "observability," proper configuration and tuning, substation architecture design and standards, a functioning communications infrastructure, a central phasor data concentrator (with appropriate design, architecture, modeling, and work processes), and data conditioning and linear state estimation. He said all of these components must be in place for a PMU to function as desired. There are many misconceptions about linear state estimations, according to Gardner, but even one PMU can provide data for a linear state estimation; full PMU coverage is not required.

Gardner explained that Dominion helped develop an open-source linear state estimator that can quickly and directly measure the system state.[4] He noted that being open source is a key attribute for the future of utility software, and he

[4] See the CodePlex website at http://phasoranalytics.codeplex.com (last updated July 7, 2015).

believes it is one that should be more widely adopted in the utility space. During a later breakout discussion, a participant stated that it would also be helpful to the research community at large to have an open-access repository of data, although others expressed concern about the privacy and security of such a repository and the challenge of reconciling data from sources with subtle differences.

Gardner mentioned that visualization provides simple and intuitive ways to present new data. For example, trending and strip charts through RTDMS (Real Time Dynamics Monitoring System)[5] show voltages, line flows, system frequency, and angular separation. Other examples include one-line switching diagrams that mirror energy management system navigation and assist human interpretation while improving accessibility by leveraging data connection and providing flexibility when needed. Visualization is not just for control centers, Gardner stated; it assists engineers and back-office staff in decision making and research.

Synchrophasor data have many uses, according to Gardner, such as for validation of models and detection of equipment failure, geomagnetic disturbances, system oscillations, and islanding. Higher-resolution synchrophasor data often appear "fuzzy" because the data contain more information, so the issue becomes discriminating between important and unimportant information. He said an important issue is how to train end users to use synchrophasor data and applications. Dominion created an operator training simulator that brings together electromechanical and electromagnetic dynamics, the closed-loop relay/PMU interface, virtual PMUs streaming data, operator-in-loop run-time controls, and visualization software.

Gardner commented that it is time to use some of the recent gains from synchrophasors applied at the transmission level and apply them to the distribution level to enhance the management of distributed renewable resources.

Looking at the larger picture, Gardner mentioned that utilities are dealing with many types of data and models in addition to those of synchrophasors. For example, information management for utilities often includes models and data from operations, planning, system protection, dynamics, markets, and assets. Unfortunately, he said, it is common for each tool to require its own network model in its own proprietary format and for every program to have its own users and maintainer. Gardner said communications between models is sub-optimal—for example, where two models reference the same network asset, the descriptions may differ. Both technical and organizational "silos" contribute to these problems.

Gardner believes the industry needs a network model data management system that can take in diverse signals (such as generation resource registrations, operations and planning network model changes, and outage and construction information) and output aggregated data (such as topology, ratings, and contingencies; outage

[5] Phasor-RTDMS is a synchrophasor software application. See the Electric Power Group's website at http://www.electricpowergroup.com/solutions/rtdms/index.html (accessed July 24, 2015).

evaluation; market participation notifications; system and substations one-lines;[6] outage scheduling; metering updates and settlement points; and transmission planning future cases). During a later breakout session, participants noted that model complexity increases with the introduction of many power-electronics devices, and it is unclear how much detail about these new devices should be included when building a grid-level analytical model.

Gardner summarized the following key problem areas: data silos, lack of a semantics layer on top of the data, lack of cross-system integration, difficulty sharing data and models, excessive time used to validate data/models, data inaccuracy and inconsistency, common data not being in sync and up-to-date, and difficulty propagating data changes to all pertinent data destinations.

Gardner concluded by noting that workforce turnover is increasing and there is a need to ingrain knowledge in data so that important information is not dependent on the experience base of individual staff members.

[6] A one-line diagram is a simplified notation for representing a three-phase power system.

4

Optimization and Control Methods for a Robust and Resilient Power Grid

The third session of the workshop, chaired by Jeffery Dagle (Pacific Northwest National Laboratory), concerned issues related to optimization and control methods for a robust and resilient power grid. Presentations were made by Pravin Varaiya (University of California, Berkeley), Sean Meyn (University of Florida), and Robert Bixby (Gurobi Optimization).

DURATION-DIFFERENTIATED ELECTRICAL SERVICE FOR INTEGRATING RENEWABLE POWER

Pravin Varaiya, University of California, Berkeley

Pravin Varaiya began by saying that there is a crisis facing utilities over the next decade. Currently, consumer demand for electricity is met mostly through base generation (by large, efficient generators that cannot be switched online or offline quickly), to which is added a small fluctuating supply of renewable energy supplemented with reserve generation that can be altered quickly. Typically, he explained, utilities make a profit selling electricity from the base load but incur losses when they have to draw electricity from the reserve. This status quo looks to change considerably by 2020, when both the demand and the proportion of renewables will likely be higher. Varaiya believes the utilities may need to raise electricity prices by that time because the greater use of renewables will lead to less use of profitable base generation, yet expensive reserve generating capability will be needed because of the intermittent nature of renewable sources. Raising prices can affect the electricity market, Varaiya cautioned, because as prices increase, consumers are more likely to turn to distributed electricity generation sources (such as rooftop photovoltaic panels) to lower prices, thereby increasing the renewable fluctuation in the market and furthering the dependence on reserve electricity to fill the gaps.

One alternative to this approach is to attempt to tailor the demand to match the renewable supply, Varaiya commented. The ideal outcome would be to modulate the demand to align closely with the renewables available and minimize the reserve electricity used. He said this would result in less overall CO_2 while enabling utilities to continue to sell a large portion of electricity from their more efficient base units. The flexible demand necessary to make this alternative a reality requires identifying tasks whose power demand can be shifted over time, modulated, or curtailed.

Varaiya believes all consumers have this flexibility, but there are challenging questions: How can the utility ascertain and quantify this demand flexibility? How can the utility extract the flexibility so demand matches the random renewable supply? He proposed that the key is to incentivize demand through product differentiation.

Currently, Varaiya noted that electricity service is a homogeneous product, but there are services to capture different kinds of demand flexibility:

- Priority pricing (Chao and Wilson, 1987), where higher-priority tasks pay more;
- Interruptible electrical power (Tan and Varaiya, 1991), where more reliable service costs more;
- Demand response (FERC, 2011a), where demand reduction below a baseline is incentivized;
- Price-responsive demand (Chao, 2010), where real-time price equals marginal cost;
- Deadline-differentiated service (Bitar and Low, 2012), where deferrable tasks pay less; and
- Duration-differentiated energy service, with fixed power, flexible time, and different durations, where, for example, a consumer can purchase 1 kilowatt for any number of hours within a preset window.

Varaiya stressed that providing consumers with duration-differentiated energy service to meet time-flexible demand requires the use of mathematical models. He discussed a simple illustration of such a model as follows: time is partitioned into slots (usually hours), and energy is partitioned into discrete units. Each task needs, at most, one unit of energy in one slot but can span multiple (sometimes discontinuous) slots. The consumer is indifferent to which time slots the task is assigned. The algorithm then ranks the tasks in order of how long (or how many slots) are required to complete the task; this makes up the demand profile. A renewable profile is defined, and the model checks whether the renewable profile is adequate to meet the energy demand needed to complete the tasks. If it is, the model determines how the electricity should be allocated among the tasks. If it is not, the minimum additional energy needed to make the supply adequate is determined. The model needs to characterize the many potential supply profiles that could meet the required demand.

Mathematically, Varaiya said, this can be represented as an "allocation matrix" (shown in Figure 4.1), with the number of columns equal to the number of time slots and the number of rows equal to the number of tasks. Each matrix element is set to either 1 or 0, denoting, respectively, that a task either will or will not receive power during that time slot. Each column sum must be less than or equal to the power available for that slot, and each row sum is equal to the total power that a task requires.

Suppliers, he said, need to determine if the given supply is adequate for the given demand. If it is, they need to determine how the supply should be allotted to consumers; if not, they need to determine how much additional supply is needed to serve the demand. Varaiya explained that this is done by the "longest leftover duration first rule," where the task with the longest duration left to completion is served first, and the tasks are reordered with each new time slot. An optimization

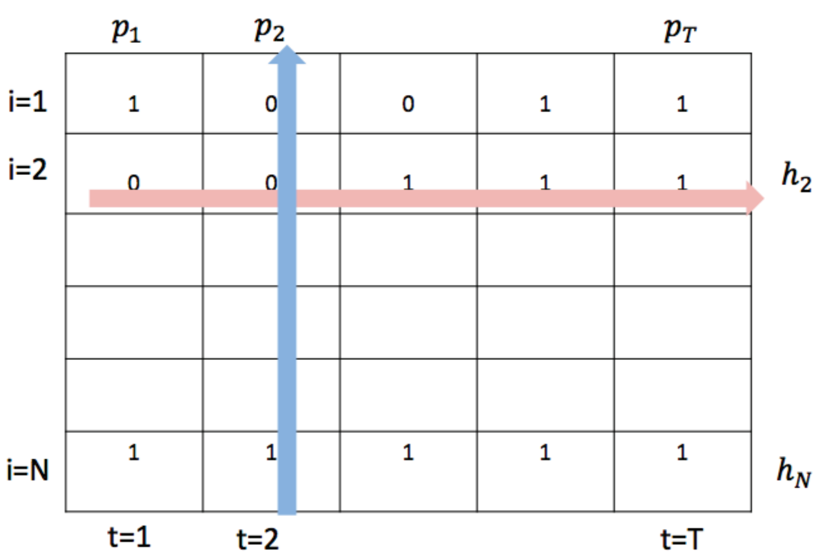


FIGURE 4.1 Allocation matrix, given the renewable energy supply profile $\mathbf{p} = (p_1, p_2, \ldots, p_T)$, consumer demand profile $\mathbf{h} = (h_1, \cdots, h_N)$, and tasks $\mathbf{t} = (1, 2, \ldots, T)$ for N tasks. SOURCE: Pravin Varaiya, University of California, Berkeley, presentation to the workshop.

problem can determine the minimum additional energy needed to complete all necessary tasks.

Another issue discussed is determining how many units of energy each consumer should receive. Varaiya said there should be an incentive mechanism to reveal how much flexibility each consumer has. The market also has to reach equilibrium on the transaction price for the service provided while also maximizing social welfare.

Social welfare maximization, Varaiya explained, could be described as a convex utility function where consumer satisfaction increases with the number of time slots available. The challenge is getting the market to indicate when consumers' needs are sufficiently met. He explained that duration-based prices could be used, in which consumers pay based on the number of time slots requested. This allows consumers and suppliers to make purchase and production decisions, respectively, based on prices. The market is in competitive equilibrium, he said, if consumers and suppliers maximize their individual utility and revenue (profit) given particular prices. The equilibrium is called efficient if the allocation maximizes social welfare. Not all utility functions are convex, however, and Varaiya said that determining equilibrium solutions is not straightforward. Research on these solutions is ongoing. Varaiya listed other areas of research, which include considering heterogeneous consumers, examining rate-constrained energy products where total energy and consumption rate are fixed but flexible in time, and factoring in uncertainty.

Varaiya concluded by summarizing that variable supply requires moving beyond the current practice of tailoring supply to load. He said that new types of energy services can be used to tailor demand to variable renewable supply, and services that incorporate demand flexibility can provide the right incentives for consumers. He believes duration-differentiated services can be a valuable tool in the future.

DEMAND-SIDE FLEXIBILITY FOR RELIABLE ANCILLARY SERVICES IN A SMART GRID: ELIMINATING RISK TO CONSUMERS AND THE GRID

Sean Meyn, University of Florida

Sean Meyn focused on demand-side flexibility for reliable ancillary services in a smart grid, specifically eliminating risk to consumers and to the grid. He also addressed some of the challenges utility and generation companies are facing, such as large sunk costs, engineering uncertainty, policy uncertainty, and volatility.

Volatility impacts many areas of grid analysis, Meyn explained, but it is especially important when addressing renewable energy integration. Meyn suggested using a control perspective to manage this volatility, giving the example of electricity generation and load shown in Figure 4.2, which includes the fluctuation of wind

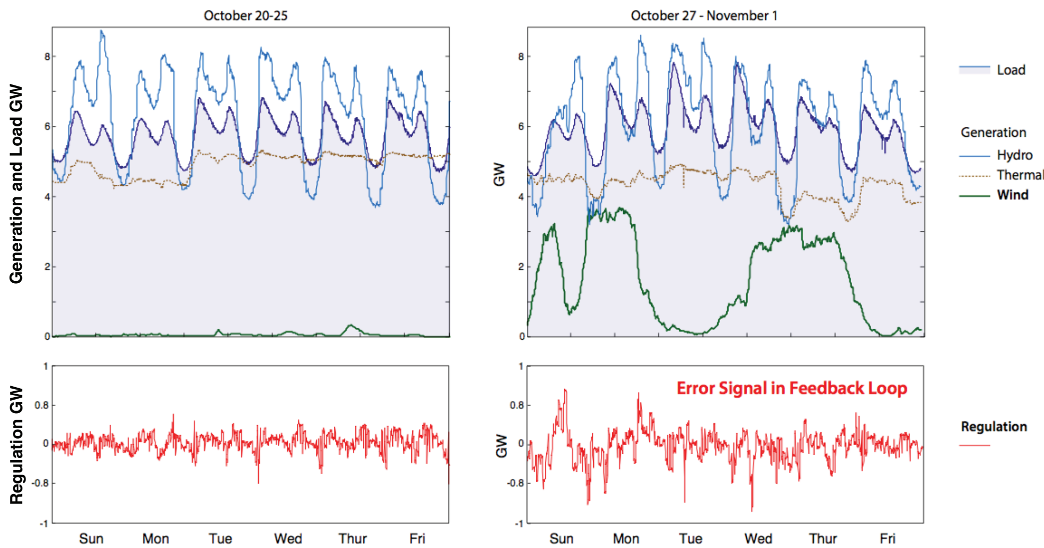


FIGURE 4.2 Generation and load variability over a two-week period (*top*) and the associated regulation signal (*bottom*). SOURCE: Sean Meyn, University of Florida, presentation to the workshop.

generation during a 2-week period in a region of the Pacific Northwest. At its peak, nearly 4 gigawatts (GW) of wind energy was generated, but there were long periods with nearly no wind generation. Figure 4.2 also shows the regulation signal used to tell generators to ramp up or ramp down so as to complement the availability of the wind energy. Note that when wind generation ramped up to 4 GW, it caused large oscillations in the regulatory signal. Meyn said that resources are needed to respond to this regulatory signal, and they are called *ancillary services*. Figure 4.2 reflects that region's use of hydro-generators as an ancillary service, but the same service could be supplied through other means, such as flexible loads.

Meyn provided the analogy of airplane flight control, which has an automated system and human pilots. He believes that the electricity industry needs to have aileron-like capabilities that can accurately ramp up and ramp down to smooth the variability from renewables such as wind generation. The balancing authority in this case is the autopilot and human pilots; ancillary services (generators that need to ramp up and down) are the ailerons on the wing that help stabilize the plane when it is rolling or banking; and the grid is the mechanical system on the plane that has to coordinate the instructions from the control system with the output of components such as the jet engines.

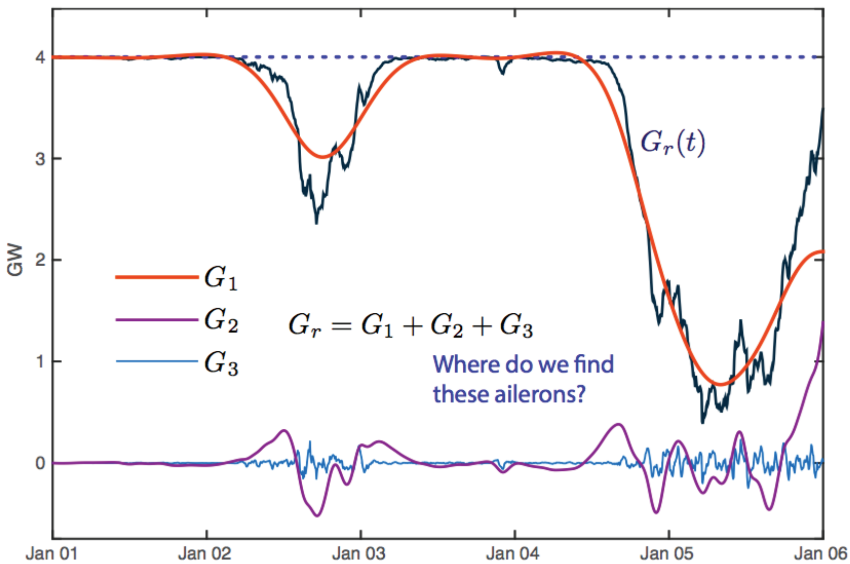


FIGURE 4.3 Example electricity load needed to supplement fluctuating wind energy (*black*). SOURCE: Sean Meyn, University of Florida, presentation to the workshop.

He provided an example to show how generation from wind could be supplemented to supply a load of precisely 4 GW over 24 hours. The residual generation is divided into the sum of three components shown in Figure 4.3, distinguished by frequency content. He said the lowest-frequency component could be supplied by forecasting supplementary energy needs and smoothing this function to something that a baseload generator (such as coal) could handle. This is denoted as the red G_1 curve in the figure. The smaller but more dynamic electricity needs—the purple G_2 line—could then be met with a quick-to-respond supplier, such as hydro. With all of these loads taken into account, there is still a high-frequency oscillation—the blue G_3 line—that needs to be addressed. Meyn commented that this high-frequency load is difficult to match exactly with a gas generator, for example, but could easily be met with a nickel-metal hydride battery.

Alternatively, Meyn said, the two higher-frequency, zero-energy signals could be supplied through flexible loads. For example, G_2 might be obtained from loads such as irrigation, refrigeration, or district hot water, while G_3 could be obtained from modulating fans in commercial buildings (many gigawatts of capacity are available in the United States). Regardless of the resources used, Meyn noted that the control architecture illustrated in Figure 4.4 is one in which all resources work independently to regulate the grid on every timescale.

Meyn emphasized that several considerations must be taken into account to make this acceptable to consumers and to the grid:

- *The ancillary services must be of high quality.* Does the deviation in power consumption accurately track the desired deviation target? Regulation service from generators is not perfect (Kirby, 2004). For example, coal-fired generators do not follow regulation signals precisely.
- *The ancillary services must be reliable.* Will they be available each day? While this may vary with time, the capacity must be predictable.
- *The ancillary services must be cost-effective.* How can installation, communication, maintenance, and environmental costs be managed?
- *Consumer incentives for reliability must be effective.* Will consumer incentives be consistent and transparent? For example, if a consumer receives a \$50 payment for one month and only a \$1 payment the next month, will there be an explanation that is clear and acceptable to the consumer?
- *Consumer quality-of-service needs must be met.* Will the consumer's experience and service be sufficient and satisfactory?

If done correctly, Meyn said, demand response could satisfy all of these constraints. This could be approached in two ways: like a regulator or like a control engineer. He said a regulator such as the Federal Energy Regulatory Commission (FERC) would partition the needed load for this example by applying traditional generation to G_1, FERC Order 745 (134 FERC ¶ 61,187) to G_2, and FERC Order 755 (137 FERC ¶ 61,064) to G_3. FERC 745 was issued in March 2011 to provide demand response compensation in organized wholesale energy markets, and it was concluded that paying the locational marginal price could address the identified barriers to potential demand response providers. However, Meyn commented that FERC Order 745 was short-lived because of state jurisdiction issues. It was also

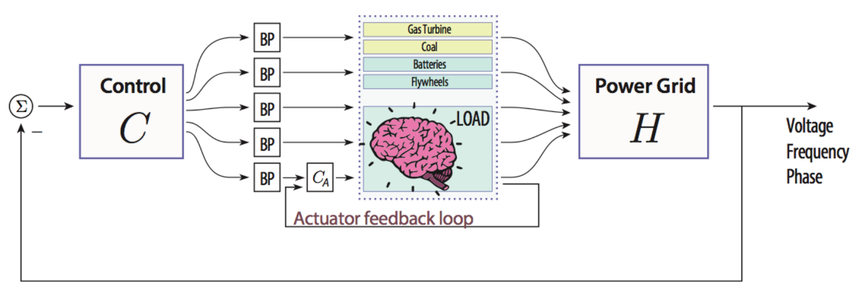


FIGURE 4.4 Illustration of control architecture with frequency decomposition for demand dispatch.
SOURCE: Sean Meyn, University of Florida, presentation to the workshop.

plagued with controversy over "double payments," where a consumer was effectively getting paid twice not to use electricity—by not paying for the electricity used and for receiving a payment for not using it. Meyn claimed that FERC Order 745 had to end because its goal of shaving peaks, resolving contingencies in seconds, and smoothing marginal cost is in contradiction to the market's need to profit. He said there is no business incentive to make investments (and incur sunk costs) if prices are low, as would be the case with effective demand response.

FERC Order 755, Meyn explained, is about regulation services such as batteries and flywheels. In this case, independent systems operators (ISOs) and regional transmission organizations are required to pay regulation resources based on the actual amount of regulation service provided. In addition, he said, a pay-for-performance approach acknowledges speed and accuracy. This specifies that there be a uniform price for frequency regulation capacity and a performance payment for the provision for frequency-regulation service, reflecting a resource's accuracy of performance. However, the definition of performance is not clear. It is currently being interpreted as mileage (the arc-length of the generation curve), but this does not reflect the cost or value of service. Meyn observed that an unanswerable question underlies this discussion: What is the cost and value of regulation? Regardless, so far it appears that this order has been extremely successful at spurring industry to create new products for higher-frequency regulation services.

Meyn presented the test case of a building at the University of Florida that is effectively being used as a "virtual battery" by allowing heating, ventilation, and air conditioning (HVAC) flexibility to provide additional ancillary service—signals similar to G_3 in Figure 4.3. He stated that buildings consume 70 percent of electricity in the United States and that HVAC contributes to 40 percent of this consumption. Buildings have large thermal capability, and modern buildings have fast-responding equipment (e.g., variable-frequency drives) that Meyn said allows them to be ramped up or down rapidly. In this Florida experiment, he explained that the airflow rate in the building was modulated by 10 percent up or down. This modulation—for a building of 40,000 square feet with three air handler fans each operating on a 25-kW motor—achieved a regulation reserve of more than 10 kilowatts at the "cost" of a temperature deviation of less than 0.2 percent.

This example, Meyn explained, is illustrative of the tens of gigawatts of reserve available from commercial buildings in the United States. He said these buildings are well suited to balancing reserves and other high-frequency regulation resources, and this reserve source functions better than any generator. Meyn noted that computing baselines is no longer important because a utility or aggregator is responsible for the equipment and compensates the building owner accordingly.

Swimming pools in Florida provide another opportunity for the electrical industry, according to Meyn. The average pool filtration system circulates and cleans for 6 to 12 hours every day and uses approximately 1.3 kW per week. This filtration is usually invisible to owners unless the pool is not getting clean enough, so Meyn believes this load could, in principle, be cycled on and off to balance overall system loads. He said a randomized control strategy could be developed to turn pool pumps on or off according to a probability that depends on each pool's internal state and the utility's regulatory signal. A mean-field model is used for this analysis, and the input-output system is stable and passive as desired.

Meyn concluded his talk by providing some supplementary references relating to these topics: Brooks et al. (2010); Callaway and Hiskens (2011); Hao et al. (2012); Hao et al. (2014); Meyn (2007); Meyn et al. (2014); Meyn and Tweedie (1993); Schweppe et al. (1980); and Parashar et al. (2004).

In a later breakout session discussion, a participant noted that there would not be much need for ancillary services if all the distributed resources were utilized. Specifically, the participant commented that two key questions need to be considered: How are benefits monetized to consumers? How is synchronization mathematically posed and solved? The participant believes the answer may lie in the successful FERC 755 (137 FERC ¶ 61,064) two-part payment scheme, or contracts for services currently adopted by EnerNOC and New Jersey Power and Light.

ADVANCES IN MIXED-INTEGER PROGRAMMING AND THE IMPACT ON MANAGING ELECTRIC POWER GRIDS

Robert Bixby, Gurobi Optimization

Robert Bixby discussed advances in mixed-integer programming (MIP) and the impact on managing electric power grids. He began by giving an early history of linear programming (LP). In 1947, George Dantzig invented the simplex algorithm, which gave a global view of solutions and paved the way for four Nobel Prizes in economics. In 1951, the first computer code for LP was developed using the simplex method, and by 1960 LP had become commercially viable and was being used extensively in the oil industry for refinery blending models. Around 1970, MIP, where some or all of the variables are forced to take only integral values, became commercially viable, although it took several more years for it to become widespread.

Interest in optimization expanded during the 1970s, Bixby explained, and numerous new applications of mixed-integer problems were identified. However, significant difficulties emerged. Building applications was expensive and risky, often requiring 3- to 4-year development cycles. The technology was not ready; linear programs were hard to solve, and MIP was even more difficult. In the mid-1980s, Bixby stated, there was a perception that LP software had progressed as far as it could go. He noted, however, that there were several key developments that pushed the field forward, such as desktop computing (dating from the introduction of the IBM PC in 1981) and Karmarkar's 1984 proof that interior-point methods could run in polynomial time. In the 1990s, he said, LP took off and MIP was demonstrated to work on some difficult, real problems such as airline scheduling and supply-chain scheduling.

Today, practitioners consider LP to be a solved problem, said Bixby. Large models, with millions of variables and constraints, can now be solved robustly and quickly. Challenges are still associated with MIP, Bixby commented, owing to the requirement for integer values, but this approach allows practitioners to model decision problems in many more application areas.[1] Bixby first successfully applied MIP to the electrical power industry in 1999 using the California 7-day Model.

The current MIP solution framework is a branch-and-bound approach, Bixby explained, where the integer restrictions are initially relaxed and the problem solved using LP. Each non-integer solution value is then examined and branched up and down to the nearest integer. He elaborated that the problem is then re-solved with these values, and the next non-integer solution value is examined. This will ultimately result in several solutions to the problem, and the minimizing solution is selected.

Bixby also outlined the computational history for integer programming. Dantzig, Fulkerson, and Johnson (1954) solved a 42-city traveling salesman problem to optimality using LP. Gomory (1958) introduced cutting-plane algorithms. Land and Doig (1960) and Dakin (1965) introduced branch-and-bound algorithms. The first commercial application solved with MIP was in 1969. In the 1970s, two cutting-edge commercially viable codes were introduced for the IBM 360 computer, MPSX/370 in 1974 and SCICONIC in 1976, that implemented a LP-based branch-and-bound. From 1975 to 1998, Bixby said, good branch-and-bound techniques remained the state of the art in commercial codes, in spite of many new advances in combinatorial optimization, including polyhedral combinatorics (Edmonds, 1965a,b, 1970), cutting planes (Padberg, 1973), revisited Gomory (Chvátal, 1973), disjunctive programming (Balas, 1974), PIPX and pure 0/1 MIP (Crowder et al., 1983), MPSARX and mixed 0/1 MIP (Van Roy and Wolsey, 1987), and the traveling salesman problem (Grötschel and Padberg, 1985; Padberg and Grötschel, 1985).

In 1998, Bixby said, a new generation of MIP codes came into existence. The biggest two advances for MIP were presolve and cutting planes. Presolve examined user input for logical reduction opportunities in order to reduce the size of

[1] The list of application areas is long and includes accounting, advertising, agriculture, airlines, ATM provisioning, compilers, defense, electrical power, energy, finance, food service, forestry, gas distribution, government, Internet applications, logistics/supply chain, medical, mining, national research laboratories, online dating, portfolio management, railways, recycling, revenue management, semiconductors, shipping, social networking, sourcing, sports betting, sports scheduling, statistics, steel manufacturing, telecommunications, transportation, utilities, and workforce management.

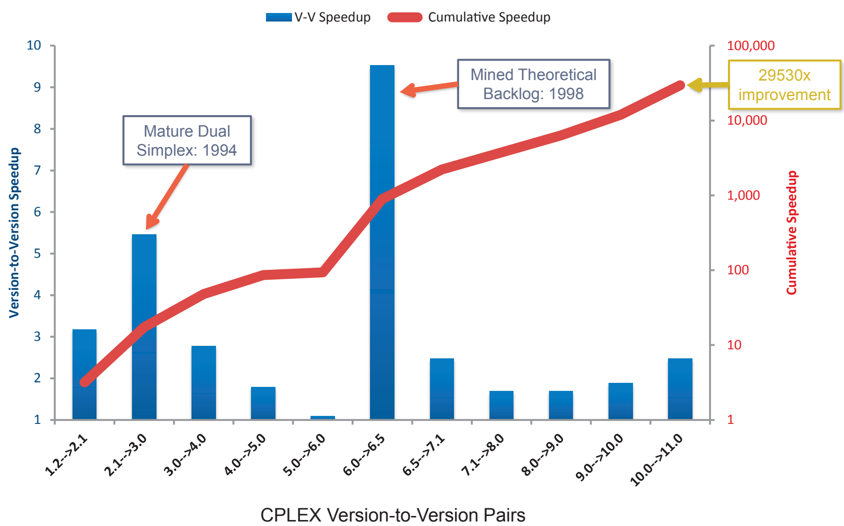


FIGURE 4.5 MIP computing time advancements. SOURCE: Robert Bixby, Gurobi, presentation to the workshop.

the problem passed to the requested optimizer, thereby reducing total run time. Cutting-plane methods refined the objective function using linear inequalities. Other advancements include improvements in LP, variable/node selection, primal heuristics, and node presolve. Figure 4.5 illustrates this rapid speedup.

Bixby recounted some major uses of optimization in ISOs and the value that MIP has provided. Optimization plays a central role in ISO operations, addressing, among others, the following three problems:

1. *Day-ahead problem.* This is the unit-commitment for the next day. For the New York ISO, for example, markets close at 5 a.m. and commitments must be posted by 11 a.m. Windows of only about 30 minutes are available to compute commitments.
2. *Real-time power dispatch problem.* This is same-day unit commitment. These are solved every 5 minutes at the New York ISO.
3. *Real-time dispatch problem.* These problems determine generator clearing prices, and they are likewise solved every 5 minutes at the New York ISO, using an LP. These solutions are comparatively simpler than the first two problems.

Bixby commented that Lagrangian relaxation, which has been in use since the early 1980s, has greatly facilitated these optimizations. Because the technique appeared to produce high-quality solutions with good solution times, there was a considerable and understandable reluctance to move away from it. However, in 1999, MIP was demonstrated to be a viable alternative, thus pressuring users to switch methods. For example, Bixby said that PJM Interconnection implemented MIP in its day-ahead market in 2004 and estimated its annual production cost savings at $60 million. Two years later, PJM implemented MIP in its real-time market look-ahead, and tests showed $100 million in annual savings. In April 2009, CAISO implemented MIP as part of its Market Redesign and Technology Update with an estimated savings of $52 million. In 2009, the Southwest Power Pool introduced MIP enhancements to its day-ahead market with an estimated $103 million in annual benefits (FERC, 2011b).

Bixby concluded by explaining that MIP is the preferred approach for three reasons:

1. *Maintainability.* The alternative Lagrangian relaxation codes were approximately 100,000 lines of Fortran code and were understood by only one or two people within an organization.
2. *Transparency.* MIP formulation has a much simpler representation with separate model and algorithm components, which are easy to read, interpret, and maintain. The solutions are also much easier to defend against legal challenges.
3. *Extensibility.* It is extremely difficult to add constraints to Lagrangian relaxation codes, while they can be easily added to MIP formulations.

5

Uncertainty Quantification and Validation

The fourth workshop session focused on uncertainty quantification and validation. The session was chaired by Juan C. Meza (University of California, Merced), with presentations by Miriam Goldberg (DNV GL) and Alexander Eydeland (Morgan Stanley).

HOW WELL CAN WE MEASURE WHAT DIDN'T HAPPEN AND PREDICT WHAT WON'T?

Miriam Goldberg, DNV GL

Miriam Goldberg discussed measurement and verification for demand response. Demand response (DR) is the process of balancing supply and demand by reducing demand to match supply. This is contrary to the conventional approach of assuming that demand is inelastic and supply has to meet demand. DR can be used to avoid high-priced electricity or to avoid going over the edge where there is no more supply at any price. She explained that a key point of DR is compensating consumers for what they did not do. Figure 5.1 shows where DR fits in with the other resources available to the electricity industry.

Goldberg showed an example of DR for an individual direct load program where the system operator had direct control over some of its customers' air conditioners (Figure 5.2). In this example, she explained that the actual load of the day (the solid line) is compared with the estimated reference load baseline (the dashed line). As Figure 5.2 shows, the actual load is increasing over time until it reaches a

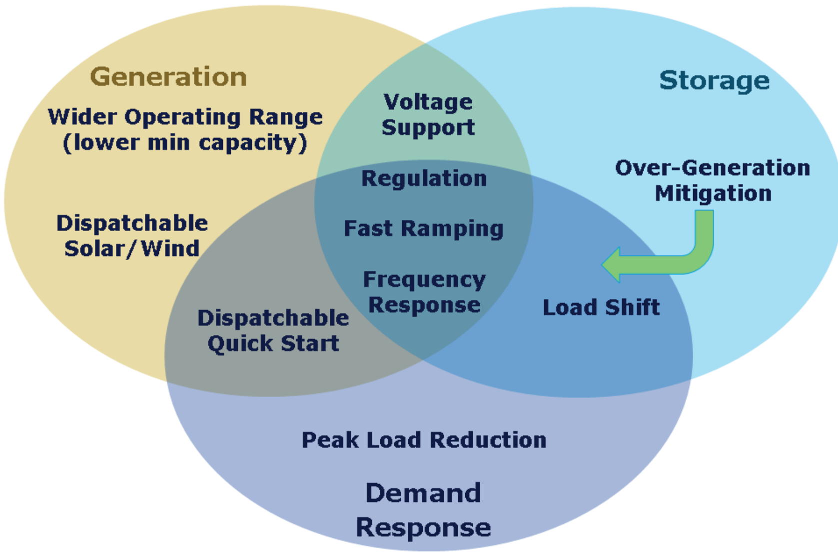


FIGURE 5.1 Demand response is shown in the available electricity resource set. SOURCE: Miriam Goldberg, DNV GL, presentation to the workshop; from CAISO (2012), copyright 2015 DNV GL.

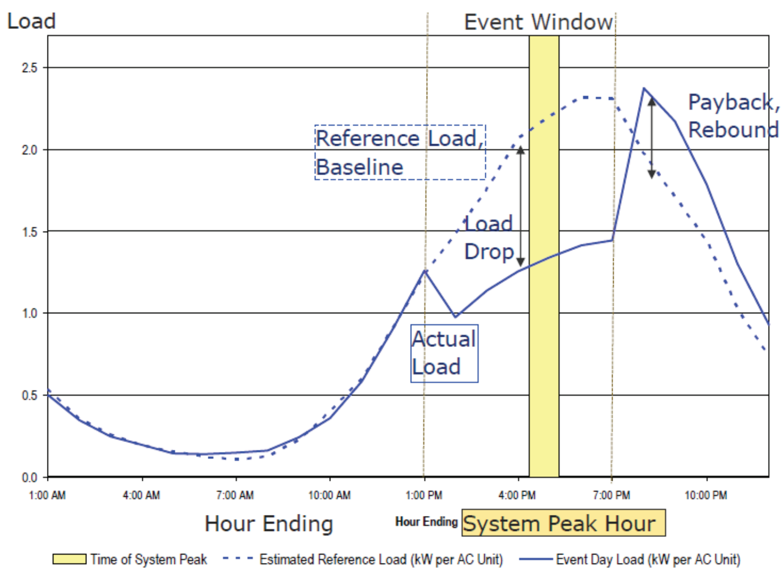


FIGURE 5.2 Example of a demand response for an individual resource. SOURCE: Miriam Goldberg, DNV GL, presentation to the workshop; from PG&E (2009).

curtailment order or curtailment signal at 1:00 p.m., at which time the load drops down. The load begins to climb again after this initial drop. Eventually, this order or signal is released (dashed vertical line at 7:00 p.m.), and the air conditioner operates normally. Goldberg noted that there is then a payback or rebound period where the actual load is higher than the reference load, because in this case the house has warmed up and the air conditioner needs to work more in order to bring the house back down to its preferred temperature. Over time, the actual load returns to what it would have been without the DR.

The fundamental measurement and verification challenge is determining a true reference load baseline, according to Goldberg. Understanding the uncertainty of this reference load is important because the system is built on compensating consumers for what was not used. She explained that the resource delivered is the difference between the load that would have been used, which can only be estimated and not metered, and the load that was used and was metered. The "capacity"[1] is the reduction that could be provided from the load that would otherwise be used. Goldberg noted that methods for calculating the reduction for financial settlement are negotiated in each jurisdiction and are often contentious. Different methods may be appropriate for different purposes. Exact "true" capacity cannot be known.

There are different kinds of measurement and verification uncertainties, according to Goldberg:

- *Estimation/forecasting errors* are standard problems with standard solutions. Examples include estimating the load that would have occurred without the DR event (statistical estimation of an unobservable parameter) and estimating the load that will occur with and without a future DR event (statistical forecasting).
- *Policy choices and conventions* determine what is useful and practical. For example, baseline methods for financial settlement need to be reasonable and transparent, not a "best" estimate. Accuracy is a consideration in those choices, but there are various ways to describe a method's accuracy.
- *Extrapolation* considers what the response will be to programs and conditions outside of current experience.

As Goldberg described it, various data are needed for measurement and verification purposes throughout the process. Before a DR event occurs, consumers have to enroll in the program, and suppliers need to determine operations and dispatch[2] rules. During enrollment, individual capacity needs to be estimated. This

[1] "Capacity" should be thought of as the capacity of the consumer to reduce consumption.

[2] For this section, "dispatch" refers to the system operator imposing limits on the customer's usage of power in response to some event.

is often done by measuring peak load or capacity of the controlled units. However, Goldberg commented, it can be difficult to rate a DR resource with a time-varying load. During operations and dispatch, the available capacity describing what the combined assets can deliver is important. This is typically done by assessing enrollment capacity using audits and evaluating historical performance. It can be challenging to predict what could be delivered if called upon.

Once a control event occurs, Goldberg explained, a financial settlement and an evaluation of how well the event worked to curtail the load are needed. This information informs additional planning of how the system can be modified or improved. Settlement requires determining individual interval reductions by comparing the observed load with the agreed baseline. However, defining a baseline that is simple, transparent, and meaningful can be difficult, according to Goldberg. During the evaluation stage, the combined reductions are examined to see what combined assets were delivered and what will be delivered in the future under potentially different conditions. This examination compares observed aggregate load versus the baseline and evaluates the modeled load with and without the event. Some key considerations include estimating the load that did not occur and assessing the measurement accuracy. In planning for future combined reductions, Goldberg said, these data help inform what the model load and enrollment may be if conditions or rules change. An important part of the planning phase is assessing the uncertainty within the system.

Baselines can be computed in a variety of ways, Goldberg explained, but typically the approach involves computing average hour-by-hour kilowatt-hour usage over a set of recent business days. This may be done in a number of ways, and Goldberg mentioned averaging the last 10 business days; dropping the highest and lowest values of those 10 days and computing the average of the remaining 8 days; and looking at the 4 highest kilowatt-hour days among the 5 most recent days. This baseline can then be adjusted up or down (known as *day-of-flow adjustments*) to match the observed load in the hours just prior to the start of the event.

Goldberg identified other baseline computing approaches, including the following:

- *Moving average:* a weighted average is calculated based on 90 percent of a previous baseline and 10 percent of the usage from the most recent day.
- *Regression model:* data on the day type, weather, daylight, and lags are all used as inputs.
- *Match day:* a prior similar non-event day for the same account is used as a comparison.

Goldberg noted that taking the average of the most recent days can be misleading because they are typically milder than the day when a control event occurred, as shown in Figure 5.3. She said that shifting the load (either by an additive or a multiplicative scalar adjustment) to match at a particular point can improve the estimate in some ways, as shown in Figure 5.4. The accuracy of these shifted estimates can be assessed by looking at the error, which is the difference between the estimated baseline and the actual load. The bias and variability of the error in the system need to be assessed. Goldberg explained that bias here is the systematic error over the hours and days, and the variability is the difference in the magnitude of the error over the hours and days.

Baseline accuracy can be assessed only by comparing actual load with baseline load on non-event days, or for accounts that are not dispatched, or by comparing simulated load reductions from actual load with the calculated reduction from the baseline, according to Goldberg. This assumes similar behavior for non-event days or non-dispatched accounts. She believes that assumption is reasonable if two conditions hold: (1) event days are similar to non-event days, and (2) the accuracy, calculated from enrolled accounts or non-dispatched accounts, uses a large random subset of homogeneous enrolled residential accounts. However, the behavior of participants may differ depending on their participation in the program or on their anticipation of an event day (for example, precooling and rescheduling working

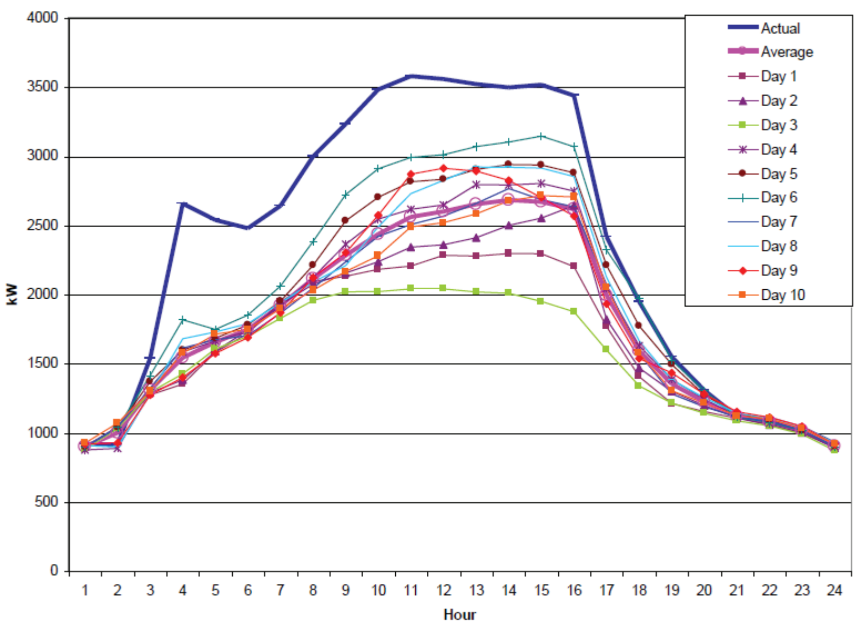


FIGURE 5.3 Illustration of baselines calculated by averaging. SOURCE: Miriam Goldberg, DNV GL, presentation to the workshop; copyright 2013 DNV GL.

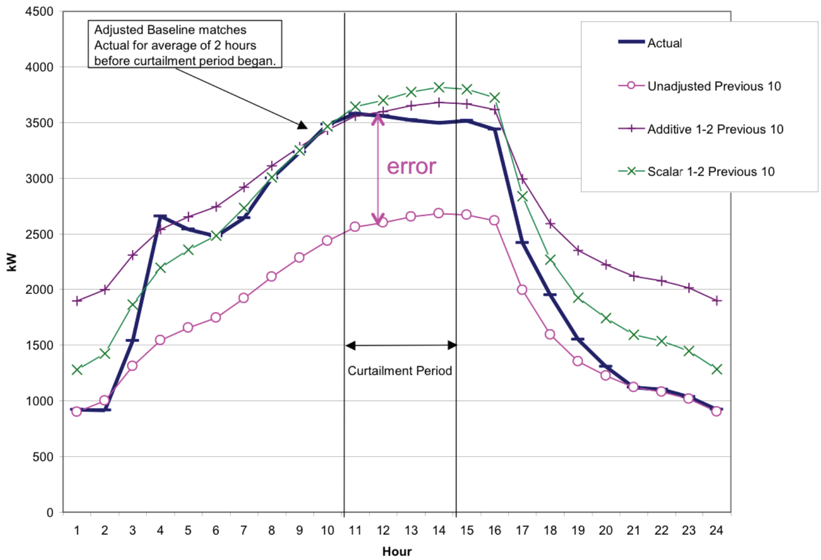


FIGURE 5.4 Additive and scalar adjustments to the 2 hours prior to curtailment. SOURCE: Miriam Goldberg, DNV GL, presentation to the workshop.

shifts). In addition, Goldberg noted that some loads are also highly variable and cannot be predicted well just from historical data.

There are two key challenges in assessing baseline accuracy, according to Goldberg. First, one needs to assess the most useful way to measure accuracy across accounts and hours, which includes computing the baseline error for an account over a specified time interval. Then, the relative error (the average hourly error divided by the average hourly load) is computed, which is useful for representing accuracy across loads of varying sizes over a population of customers and various time intervals. This can be computed over each account interval separately, or computed over longer time intervals. The median relative error across accounts and time intervals also needs to be computed. Goldberg noted that it is most useful to look at error in calculated reductions, not just in load. This requires a known, assumed, or simulated reduction quantity. She noted that if load reduction is 10 percent of load, a 10 percent baseline error is a 100 percent error in the delivered reduction.

Another consideration is how to rate a resource with time-varying load. This requires determining what is meant by DR capacity for a load with time- and weather-varying reductions. The enrolled capacity will tend to be based on peak load or reduction at peak load, which makes sense if events will mostly be called at peak conditions. The NY ISO, she mentioned for example, computes an individual asset's top 20 out of the system's top 40 hours (by season), an individual asset's peak load (also by season), and an individual asset's top X of Y hours (by month).

Goldberg explained that to predict what load capacity could be delivered if needed, a program dispatch operator needs to know the available reduction at each point in time and then track whether load reduction is happening by looking at an asset's current load level relative to where it should end up. To do this, the dispatcher needs to know any two of the following three types of information:

1. The load going forward if there was no dispatch (the *upper dispatch limit)*,
2. The reduction that will occur if called (*commitment*), and
3. The load that will occur under full dispatch (the *lower dispatch limit)*.

Under some market rules, Goldberg explained, the operator does not have to dispatch the full commitment and could instead ask for only part of it, ranging from the lower to the upper dispatch limit (known as the *dispatchable range*). Estimating what the load will be if no dispatch is called can require a continually adjusted baseline. At each interval, she said, the adjustment is updated to recent intervals if not dispatched. If multiple events can be dispatched in 1 day, the operator needs to determine the available capacity after release of the prior event. In principle, the same adjustment method can work that was used in the first event, Goldberg said, but this is under study for ISO New England. Specifically, she noted that the study is considering the following questions:

- How far before first dispatch should the adjustment window go?
- How long a span should the adjustment window include?
- How much downtime or recovery is needed after the first event?

Determining the real-time baseline answers the capacity question in principle because load reduction is committed, and the real-time baseline indicates whether the load is available to reduce that much over a potential event. However, Goldberg noted that actual performance may vary. Calculating available capacity based on the baseline and committed reduction assumes the same reduction will occur no matter when or in what condition the event is called. She said this is often not realistic, depending what the load reduction action is (e.g., weather-sensitive responses will not always provide the same reduction). In an ideal program, the load reduces by the amount dispatched (and not more) just as a generator supplies what it is told and not more. This is harder for DR participants unless their response is shutting down a fixed load.

Goldberg stated that the fundamental challenge for DR planning and operations is forecasting response. These forecasts involve determining the load reduction possible from currently enrolled customers, specifically for each participating asset and for the aggregate of dispatched assets, at each point in time from notification through rebound as felt on the system. Equally important, she said, is estimating the number of non-dispatchable customers at a given time, taking into account dynamic rates and their price responsiveness. For future planning, forecasters must know how much responsive load there will be and how that load will respond (as a function of prices, weather, time, etc.).

Forecasting what will happen in response to a price, among other factors, Goldberg said, is commonly thought of as an elasticity problem. She noted that this is really a set of intersecting elasticity problems involving long-term investments, seasonal enrollment, monthly bid or obligation, day-ahead response, hour-ahead response, and minutes-ahead response. The choices and responses at each timescale affect options and responses at the next scale, and expectations for later time points affect decisions at earlier stages.

However, Goldberg said, demand tends to be inelastic and customers are non-responsive to short-term price fluctuation, mainly because of timing. Traders are buying and selling fixed blocks in long-term contracts, with small amounts of load-following supply, and most customers are not interested in being exposed to volatile prices. She said there are a few factors that can make customers more responsive to price, including moving to more volatile real-time prices, higher costs, automating DR, a high normal load, and discretionary/deferrable load urgency. Customer expectations of price volatility, costs, and load urgency affect prior decisions that in turn affect current price exposure and equipment capability.

Overall, Goldberg said, managing DR uncertainty involves improving measurement with better retrospective and forecasting models, accommodating response uncertainty in dispatch, and making participating loads more predictable.

She observed that the predictability for enrolled DR participants can be improved by shutting out the noise of customers with highly variable loads, by screening loads out of the program based on predictability criteria, and by requiring highly variable loads to give day-ahead predictions (and set penalties for over- or under-prediction). Adding more information can also help, Goldberg explained, by requiring highly variable loads to give day-ahead notice of major changes. It is also important to limit the potential for gaming the baseline, usually by limiting participants' ability to control or predict when they will be dispatched and investigating load and bidding patterns that seem perverse. Operators can also help participants become more predictable by facilitating technologies that automate DR and offering retrocommissioning[3] and (re)training.

[3] "Retrocommissioning" is a systematic process for identifying and implementing operational and maintenance improvements.

Goldberg said this is also an issue of improving predictability for all loads, often by incorporating supplemental customer information from other sources (such as clustering customers into industry types) and using pattern recognition to identify operating modes.

Goldberg concluded by summarizing the outstanding problems related to DR uncertainty and uncertainty reduction:

- Estimating elasticity (as interrelated response curves), including enrollment in variously configured program/product offers and determining response to prices/event dispatch when enrolled as functions of customer characteristics, calendar, hour, weather, and prior responses;
- Calculating capacity dynamically for time/weather-varying loads;
- Using pattern recognition to improve forecasts and back-casts;
- Projecting response trajectories through the duration of an event and after release with error bands;
- Relating true aggregate system reduction to the nominal reductions calculated for financial settlement, on a dynamic basis, with error bands; and
- Establishing baseline bias and variance as functions of customer characteristics, event day type, and event duration.

Overall, methods and results for DR measurement and verification affect and are affected by many aspects of program planning, design, and operations, and Goldberg emphasized that it is important that uncertainty be well understood.

MATHEMATICAL MODELS IN POWER MARKETS

Alexander Eydeland, Morgan Stanley

Alexander Eydeland discussed some mathematical models of power markets. In his presentation, two underlying assumptions were that a relatively liquid market is needed and that uncertainty is due exclusively to randomness of market prices. He explained that the objective is to acquire a commodity asset (such as a power plant, freight, oil/gas storage facilities) through a competitive auction. This requires both determining the appropriate asset price and developing a strategy to extract value from the asset. Commodity derivatives are investment tools for assessing a portfolio of financial options on assets with an associated strategy of how to extract value from the assets. This strategy is based on Black-Scholes theory, which Eydeland characterized as taking an investor's assumed distribution of underlying prices and desired option payout and computing a formula and hedging strategy to allow the investor to lock in a value.

Eydeland gave the example of a merchant power plant that has the option of running if the market price of power is higher than the cost of fuel plus variable operating costs. Net profit from this operating strategy is given by

$$\Pi = \max\left(\text{Price}_{Power} - \frac{Heat - Rate}{1000}\text{Price}_{Fuel} - Variable - Costs, 0 \right).$$

Eydeland stated that operating this merchant power plant is financially equivalent to owning a portfolio of daily options on spreads between electricity and fuel (known as *spark spread options*).

Modeling the power plant commodity asset consists of three basic steps, according to Eydeland: (1) finding an appropriate process for price evolution, (2) defining the payout function, and (3) finding expected value (using methods such as Monte Carlo simulation, partial differential equations, and fast Fourier transforms). He noted that computing the payout function is often complicated. In the example of the power plant, technical considerations need to be included, such as the price of the emissions, ramp-up rates, and number of start-ups allowed per year for a given turbine. Eydeland said defining the appropriate stochastic process for price evolution is usually even more complicated.

For power prices, he said, a few key attributes can be modeled, such as mean reversion, spikes, high kurtosis, regime switching, and non-stationarity. The correlation between power prices and natural gas prices also has a unique structure that can be modeled as a joint distribution. (If the model does not capture this structure, it may misprice spread options.) Eydeland explained that this correlation can be modeled through a variety of approaches based on geometric Brownian motion. However, this alone does not capture the key behavior of power prices well. Models can then incorporate mean reversion and jumps (discontinuous behavior) to attempt to capture the necessary behavior, according to Eydeland. However, these additions can increase the number of variables beyond what can be reasonably solved and managed.

Eydeland explained that the dilemma is that a highly complicated model (including models with stochastic convenience yield, stochastic volatility, regime switching, multiple jump processes, and various term structures) is needed to capture this complex behavior, but such a model becomes unmanageable and useless. He described a hybrid model, called “bid stack,” that combines the stochastic and fundamental modeling of price formation. Prices are formed by a generator supplying bids to the auctioneer (the ISO), and the ISO puts the bids together to find the optimal way to dispatch the power generation in the region. The final price is the lowest price needed to meet the day’s demand, Eydeland noted. The price versus the demand follows a particular bid stack function that, if estimated, allows the distribution of the power prices to be constructed.

Eydeland explained that the generation stack needs first to model the market fuel prices of key power sources and generation outages (usually done using government data with a standard Poisson process). Then the bid stack function is estimated by scaling the generation stack in the particular market to match the market data while preserving higher moments of price distribution (specifically, skewness and kurtosis). He said the demand can then be modeled as a function of temperature, including the evolution of the principal modes and of the daily perturbations, and used as an input for the generation stack function. The resulting output is a detailed estimate of power prices accounting for the complexities inherent in the system.

Eydeland concluded by noting that new challenges are multistack models and renewables. He also provided two additional references for additional information: Eydeland and Wolyniec (2003) and Eydeland and Geman (1999).

In a later breakout subgroup, a participant wondered how Black-Scholes models are applicable to electricity markets, particularly with respect to incorporating details of optimal power flow in determining the locational marginal price formation. Another participant asked what impact the increased penetration of renewables might have on the price formation process. A simple approach suggested would entail a simple shifting of the bid stack by zero-marginal cost renewables. A participant suggested that the ability to forecast price would then depend heavily on one's ability to forecast renewable power output, which is a challenging problem.

6

Discussion

The workshop had two mechanisms in place to receive input from participants: breakout discussion subgroups and short presentations to the full audience.

BREAKOUT GROUPS

The workshop hosted breakout sessions following each of the three workshop sessions. Each breakout group was organized as an open discussion, and many of the same topics arose across separate sessions. Comments that related directly to a point of a workshop speaker have been integrated into Chapters 2-5. However, some of the comments concerned topics not discussed in the workshop presentations, and some spanned topics from multiple presentations. This chapter captures summaries of those topics.

Using Phasor Measurement Units and Smart Meter Data to Build Better Models

The subgroups discussed whether time series data from phasor measurement units (PMUs) can be used to build better (parametric or nonparametric) models of a power system's transient response (e.g., impulse, step) to large disturbances. Specifically, can small but informative perturbations be identified that would facilitate model development and testing? One participant noted that small perturbations may not offer enough information and that using data from large unplanned perturbations (such as blackouts) may be more helpful. Another participant commented that the power system is slowly time-varying. Because this may complicate the ability to train or tune reliable models, it will be important to explicitly incorporate the time-varying composition of loads into the system identification procedure.

Another group discussed the importance of making actual and synthetic power system data sets, and the models that accompany these, available to researchers—potentially via open-source methods. A participant suggested that these data sets should span both transmission and distribution systems and go beyond data (e.g., measurements utilized by supervisory conrol and data acquisition (SCADA) systems and measurements obtained with PMUs) from the physical system to possibly include financial data and other data used in operations (e.g., weather forecast data).

In terms of making real power system data sets and their companion models available to researchers, a participant said it would be necessary to work with industry stakeholders to clear roadblocks related to confidentially. One participant noted that a possible solution to this would be to transform the data sets and their companion models so as to mask the actual system to which they correspond. However, it would be desirable for the resulting masked models to preserve the attributes of a realistic power system. A participant noted that one way to demonstrate to industry the necessity and benefits of making these data sets and models available is to point out that these have been beneficial in other industries. For example, in the 1990s, the airline industry made data and models available to researchers, which resulted in a prolific period in terms of tools and algorithm development from which the industry as a whole benefited.

A participant noted that there are standard Institute of Electrical and Electronics Engineers (IEEE) synthetic power system test models that have been used by researchers for years. However, a problem with these, as pointed out during the discussion, is that their size is not representative of actual power systems; therefore, it is not clear a priori that many tools being proposed by researchers actually scale up to realistic systems. Also, one participant noted, an open issue is how to create synthetic data sets to accompany these models with similar characteristics to those observed in data gathered from a real power system.

Over-fitting was mentioned as a concern in connection with creating libraries of power system data sets and models for researchers to test new techniques and algorithms. Specifically, if the data sets and models made available are not dissimilar enough, it could be the case that new techniques and algorithms are over-fitted: they would work well with these particular data sets and models, but they actually do not represent well other systems or contexts that differ from the models and data sets used by the researchers. Thus, the participant noted, a key issue will be to create libraries that are diverse in terms of the power systems and operating contexts that can be encountered in real settings.

Participants noted that while industry provides models, experiments, and software solutions at the transmission level, doing so for the distribution level would raise a number of fundamental challenges, specifically owing to limitations in our understanding of the underlying physics.

Real-Time Pricing

Real-time pricing (RTP) was discussed in the breakout sessions; specifically, can accurate models of customer response to real-time pricing signals be built? A participant noted that the response would naturally depend on customers' access to price information and load-shifting enabling technologies. It was noted that most RTP programs in place today rely on day-ahead communication of time-varying prices. This participant questioned whether there is any advantage to moving to true RTP. Another participant commented that many utilities are hesitant to transition to true RTP because of potential customer dissatisfaction. It was noted that many customers may have limited incentive to respond to RTP because of small potential monetary savings.

Using RTP to approach load control was also discussed. A participant noted that it may not lead to a reliable real-time response in demand and might instead increase demand volatility. Another participant commented that RTP can induce instabilities or limit cycles in the aggregate load response. A participant suggested that forward contracts for direct load control might offer a better alternative. Some questions arose from this: How would one structure and price such contracts for small residential customers? Perhaps a pricing approach differentiated by quality of service? Another participant commented that peak-time rebates constitute another incentive design for demand response. This, however, requires a reliable estimate of the customer load baseline that is difficult to produce and susceptible to gaming.

Security Issues

Breakout groups discussed how to prevent attacks on a communication and control infrastructure used to manage customer loads remotely. A participant from industry noted that control centers are highly sensitive to the cybersecurity issues, which makes using the Internet for power system control highly unlikely. Regarding grid control architecture, a participant noted that while the grid started with controlling a few points of generation, the future grid will have to accommodate millions of access points of control on the consumer side. Security breach of the grid will be of concern, and the participant wondered if an "intranet" solely for the grid would be helpful.

As a specific mathematical challenge, an academic participant proposed the following question: What is the mathematical problem in considering adversary actions against the grid? Also, what is the appropriate mathematical framework to consider low-probability, high-impact events such as geomagnetic disturbances or terrorist attacks? One industry member suggested that micro-grids may be coming. Combined heat and power would turn out to be much more resilient than the bulk power system that currently exists, especially if there is a geomagnetic disturbance event. A participant from industry made reference to China's smart grid activities, which focus more on reliability than just distributed intelligence.

Another major risk is the gas–electricity coupling. Gas pipelines deliver gas flow at a speed much slower than the speed at which electricity flows. The availability of gas as a fuel at power plants could be an increasing source of uncertainty due to the increasing number of natural gas power plants. A participant noted that the National Science Foundation's Resilient Interdependent Infrastructure Processes and Systems (RIPS) program has begun to fund activities in these areas.

Energy Storage and Renewables

A participant wondered whether electric energy storage in the form of pervasive small-scale distributed batteries would solve the variability problem of renewable energy integration. Another participant noted that plug-in electric vehicles might represent a natural path toward delivering energy storage to the power system. A participant commented that it would be important to understand how such technologies get adopted to the point where they could provide such options. Another participant questioned how to manage widespread integration of plug-in electric vehicles into the power system.

How to redesign electricity markets to facilitate the integration of energy storage into the power system was also discussed. A participant noted that capacity, energy, and ancillary service markets need to evolve. Specifically, well-designed markets should induce efficient operation of storage in the short run and expansion (i.e., placement and sizing) in the long run.

Another topic of discussion was how markets would have to evolve in order to support the large-scale integration of renewables. A participant wondered whether Germany Energiewende[1] is an example of market failure. This participant noted that Germany has many days in which there is wind oversupply (exceeds the needed load) where prices become negative. Another participant commented that the community should be wary of free-market approaches because of adverse effects, such as the California energy crisis in 2000.

[1] See the Energy Transition website at http://energytransition.de for more information (accessed July 24, 2015).

Mathematical Tools

Breakout groups discussed what current and future mathematical tools might most naturally apply to emerging problems in power (such as renewables integration and demand response). Participants made the following suggestions:

- *Game theory and mechanism design.* The (re)emergence of demand response as a tool to manage variability in renewable supply requires the delineation of new market constructs to engage residential demand-side resources. Tools from dynamic game theory naturally lend themselves to the treatment of such problems. Participants brought up the following points:

  — Consumer utility functions may be unknown.
  — Market mechanisms and schemes need to be "transparent" (i.e., easily understood by market participants).
  — Market mechanisms need to be robust to gaming, such as attempts at baseline misrepresentation in a variety of demand respond programs centered on peak-time rebate incentives.

  The trade-off between optimality and robustness was discussed, with a participant from the power industry commenting that robustness would be highly preferred. Introducing and defining the duality between game theory and mechanism design seems to be a future direction. A participant noted that optimization and control software should be designed to account for the imperfect retail market.
- *Linear programming.* Participants noted that linear programming (LP) terms and algorithms are mature and there are types of problems in the power system that LP can handle well. However, participants noted that there are some issues that LP cannot handle well, such as an explicit description of uncertainty. The existing optimization frameworks that can capture uncertainty were discussed (i.e., stochastic optimization and robust optimization), and participants raised the question of whether these are scalable to large power system problems. Several participants stated that while these tools are promising, it is necessary to do much more research until they are of practical value to the industry. A participant also commented on the necessity of including constraints that capture certain dynamics requirements.
- *Mixed-integer programming.* Some comments were made about why mixed-integer programming (MIP) has not yet prevailed in power market software. The concern stated was that MIP is highly sensitive to constraints. Some industry representatives mentioned that operators could not afford

to use MIP because the locational marginal prices were much less stable in MIP. A participant mentioned the difficulty of dealing with multiple solutions.

- *High-fidelity grid simulation tools.* Available and future high-fidelity grid simulation tools were discussed. A participant commented that reliable simulation tools are essential to informing policy decisions as they relate to the power system. This participant noted that designing a simulator that layers policy, planning, and nominal and contingency operations would be helpful. One question posed was whether there is currently a simulator capable of simulating an entire blackout at the most granular of spatial scales. A participant noted that nearly all blackouts start at the distribution level, which is not typically modeled in simulation tools. Another participant noted that disturbances in the distribution system percolate into the transmission system, and vice versa.
- *Power-flow models.* Participants discussed the inherent inefficiency of the current DC-optimal power flow and noted that the industry would benefit from moving toward AC-optimal power flow to optimize the voltage and to counteract the behavior from consumers. A participant noted that this is an area where the mathematics community could assist the ISOs' transition toward next-generation control centers.
- *Human-in-the-loop models.* The importance of building mathematical models to consider humans-in-the-loop was mentioned.
- *Data analysis.* Challenges of extracting information from massive amounts of data were discussed. Participants noted that from a mathematical perspective, numerical integration algorithms for such a hybrid dynamic system is difficult. Also, the differential algebraic equation solvers need to provide solutions for the grid operators. Another question was posed regarding how to leverage data-driven statistical models to improve upon (first-principles) physical models. Participants mentioned the following metrics of interest for new models: their computational scalability, prediction power, and integrability into real-time control schemes.
- *Understanding causality.* A comment was made about the importance of understanding causality (i.e., the physical principle) when dealing with data and modeling. Also, how can a system learn over time from the measurement data? A participant wondered if this could be done using self-organized data-based swarm control, similar to what is used in Google's driverless cars.
- *Dynamic models for stability analysis and feedback control.* Participants discussed the need for revisiting dynamic models commonly used for stability analysis and feedback control design. A participant noted that dynamic stability and control ceased to be a problem of interest for power system

researchers years ago because of redundancy in transmission systems, advanced relaying, and sufficient inertia provided by large generators. However, with the changes in structure and functionality that power systems are undergoing due to integration of renewable-based generation and other technologies, this problem may be of interest again (e.g., renewable-based generation results in decreased inertia in the system). Current centralized closed-loop power system controllers such as automatic generation control were also discussed; specifically, they may not deliver their intended function properly because of latency, delays, and other issues that are not usually included in models used to design these controllers. Several participants noted that there is a need to revisit dynamic modeling in power systems and that it might be necessary to explicitly describe the communication infrastructure for monitoring and control. By doing this, the participants noted, not only will it be possible to understand the impact of delays, packet drops, and latency that naturally arise from normal operation, but it will also be possible to quantify the potential impact of cyberattacks on system operations. Finally, it is important to note that while the discussion mostly focused on transmission systems, many participants mentioned that some of the same problems may arise in distribution systems due to the increased penetration of distributed energy resources and the increased reliance on communications and control for managing assets in these systems.

Participants noted that mathematical scientists could play a central role in improving the state of the art in power system dynamics analysis in the area of nonlinear and stochastic control and stability. The value of control, a participant noted, needs to be carefully studied in a market setting. One participant from industry commented that there is no payment for primary frequency response. One academic participant asked, Could we do micro-pricing such as is done with Internet advertising? Stochastic control is, broadly, the problem of multiperiod unit commitment. Economic dispatch with renewables amounts to the problem of a constrained sequential decision under uncertainty.

A Paradigm Shift to a Distributed Power System

During a breakout session discussion, a participant noted that distributed generation is becoming more affordable and efficient—in large part because natural gas is currently inexpensive. The subgroup discussed how the utility could be impacted if distributed generation and small storage were widespread. Other participants posed questions regarding what role distribution system operators would play and how the transition from today to this future could be managed (e.g., through markets or legislative mandate). Participants suggested three possible solutions to enabling endpoint control of distributed resources:

- Centralized control through the ISO,
- Hierarchical control through aggregators (with a to-be-determined level of aggregation resolution), and
- Fully decentralized control.

A participant noted that one challenge is how to transform optimal power flow to a decentralized approach that is scalable. It was observed that the existing SCADA systems and energy management systems (EMSs) involve information primarily from the generator side. However, multidirectional information exchange between supply and demand sides is needed in the future. Potential future micro-grids were discussed in multiple breakout sessions. A participant noted that micro-grids are touted for their favorable reliability properties; specifically, they are resilient to bulk transmission system failures and easily reconfigured. One participant posed the question of how utilities should evolve and/or what role they should play to enable the proliferation of micro-grids, and whether they should play an active role as a micro-grid operator. A participant commented that this would require the development of distribution automation systems and that distributed control theory would likely play an important role, as centralized control would likely fail to scale with the dimension of the system (e.g., 10^6-10^7 end points would need to be controlled). An academic participant posed a new vision for the grid with little or no bulk transmission-level energy production and no central operator and with all distributed systems coordinating and exchanging just like the intelligent periphery in the Internet, including peripheral mass storage. The research question then is how to conceptualize such a system mathematically, including what kind of pricing incentive or other incentives would enable such a vision, and how people's behavior would change. Nordic power systems are similar to this, one participant noted, with hydro serving as "battery storage" for the Danish wind. An industry participant commented that the question is how to transition from here to there.

Another participant from industry commented that it is not clear what the business infrastructure will be 15 years from now. For example, how much will consumers have to pay in order to be off the grid? Can the current market optimization software adapt to the future environment? The participant commented that comprehensive output analysis of software solutions is needed.

A participant questioned if the increasing penetration of rooftop solar alone has the ability to induce hardship within utilities. A participant noted that San Diego Gas and Electric has proposed a network fee for rooftop solar installations to offset lost revenue. Wisconsin and Indiana laws allow utilities to recover their fixed costs by charging rooftop solar owners a fee to cover fixed distribution infrastructure cost. The Hawaiian legislature is discussing a similar approach. Participants wondered whether this solution is temporary or desirable.

There was also some discussion of the different strategies available to combat financial hardship on utilities. A participant suggested unbundling the distribution system but wondered how this would work practically. Local power transmission and distribution was also discussed. A participant noted that it is not currently possible for one neighbor to send physical power to another and wondered what it would take to start small experiments like this. A reference was made to the phone system in the 1980s, which faced similar problems that have since been overcome. A question was raised on the analogy between the Internet and the power grid: Can the power community draw some lessons from the architectural design of the Internet and use them to design the future grid? One comment was made that in contrast to a layered architecture, perhaps "timescale engineering" architecture would be needed for the future grid.

As an attempt to pose a mathematical question, it was suggested that one consider large-scale decentralized control with stiff electrical constraints. Existing large-scale system theory does not lend itself well to many of the problems in power systems. For example, many theorems are based on the assumption of weak interactions, and they address only sufficient, not necessary, conditions. More theories tailored for the case of large power systems need to be developed.

Uncertainty

Several breakout groups discussed the issue of managing uncertainty in the grid and the importance of doing so for the future power system. Uncertainty in these discussions related to both modeling and predictive uncertainty and to variability in available power supplies, particularly from renewable energy sources.

Some framing questions were suggested, specifically, where are the uncertainties coming from in the next 10 to 20 years? What are the mathematical challenges? It was suggested that optimization under uncertainty is of paramount importance. How can scenario reduction be done without the loss of critical contingencies? As an example, the algorithm of progressive hedging can run only 100 or so scenarios within hours, but this is too slow for the industry. Another academic representative suggested that a major source of uncertainty is from demand response—even more than renewables.

Discussions about the variability of renewable energy included how to redesign electricity markets to correctly dispatch and price renewable supply. Participants wondered what information the market participants need and whether risks are being allocated fairly between suppliers and consumers.

Two sources of uncertainty discussed were weather and age. PJM experienced record heat in 2011 and 2012, and then Hurricane Sandy in 2013. A participant suggested that the power industry examine how the insurance industry manages these risks due to extreme weather to see if any lessons can be learned. The operating capability of old and aging assets, such as mechanical equipment, can introduce uncertainty as well.

A mathematician made the comment that it would be important to differentiate the model uncertainty and the stochastic characterization of model variables. In terms of uncertainty quantification, one academic remarked that the answer would be important, as would improving the confidence associated with an answer. Combining software packages can also be challenging, one participant noted, but there is not a single software package that can simulate an entire blackout.

A control theory expert mentioned that the future new technologies would be the biggest source of uncertainty. Perhaps it would be useful to look at studies carried out by the Australian Academy of Technological Sciences and Engineering, which aimed to optimize the grid under a variety of different scenarios.

A participant noted that many parameters in electrical models are uncertain. It is a challenge and, in the meantime, an opportunity to adaptively estimate these parameters using field measurements. For example, load dynamics is a major area for further improvement. One industry participant commented that verification of models works well but validation is difficult. Even if an individual component is well validated, when multiple components are interconnected the coupling and interactions make validation very challenging. Also, are the phenomena that naturally happen in a power system sufficient to validate the models for the wide range of operating conditions that can happen only infrequently?

Interoperability

The need for standards for an interoperable grid was discussed, including whether information exchange for designing such standards is important or whether it can be completely decentralized. It was noted that control and standards previously differentiated between normal and abnormal operating conditions, but more recently the boundary between normal and abnormal has become less clear. Traditional deterministic N–1 approaches in reliability standards would be too costly and unreliable. A participant suggested that a risk-based approach is needed.

A power system engineer made the point that the power grid was indeed designed to be plug and play. The automatic generation control was designed to perform such functionalities with control-error information from a very limited area. A participant wondered whether such information simplicity can be retained.

Markets on Shorter Timescales

Another issue discussed was the incentive mechanisms available in closer-to-real-time electricity markets. Participants commented that it is difficult to provide incentives for faster-timescale markets and that the transient impact of smart appliances will likely have a noticeable impact on maintaining the stability of the grid.

An industry participant mentioned that most of the energy transactions are committed in day-ahead markets. Only a very small portion of the energy is transacted through real-time markets, which is settled in real-time locational marginal pricing.

Another industry participant reiterated the point that power electronics could be smart and fast but that this requires a different paradigm of control in comparison to traditional resistive load. Yet another industry participant spoke of the importance of centralized and distributed optimization methods, in particular, with demand response and an even larger number of decision variables.

High-Voltage Technology and Power Electronics Improvements

Another window of opportunity discussed for the future grid was high-voltage direct-current (HVDC) technologies or, more generally, making the wires more efficient. A participant noted that a more futuristic view would be creating a grid of HVDC. A difficult technical challenge would be how to do protection and control in an HVDC-meshed network. An academic participant followed up and posed a question about network-level flexible alternating current transmission systems (FACTS) devices control for grid-level performance. It was noted that there will likely be many smaller and smarter switches in the future, and coordinating them may be challenging. A participant noted that it would be important to calculate the grid's economic and technical benefits by introduction of HVDC, and China's deployment of HVDC may be an example.

Along this line of discussion, it was mentioned that phase shifters are often not well coordinated in the optimization models. It is a computational challenge to integrate flexible control into the market-clearing software and to consider post contingencies.

Several attendees discussed the fundamental challenge of protection in a power grid that is rich with HVDC and FACTS devices. AC protection, the HVDC protection, does not cross zero;[2] therefore, one needs to shut off all equipment in order to do protection. This is a major challenge for the hardware community. The topic of

[2] Alternating currents oscillate and cross zero every half period, which creates conditions for self-extinguishing of currents in mechanical circuit breakers. In a direct current system, there is no such natural zero crossing, and currents must be forced to zero by external means before mechanical switches can be opened (Cairoli et al., 2010).

protection was further discussed. More research is needed to move from protecting equipment to protecting the system. For example, how do we adaptively learn the setting point and control logic of a relay setting. This is a potential area where mathematics could play a central role, as machine learning and intelligent alarm processing will be crucial.

Updated Data and Models Needed

Regarding data sharing among utilities, one industry representative commented on the Fedral Energy Regulatory Commission Critical Infrastructure Protection cybersecurity reliability standards, which may have kept the data away from most researchers. Another industry member commented on the outdated software codes that underpin much of today's core software. Many solvers were written decades ago with Fortran code that is no longer upgradable. Much of the software is company proprietary, which makes benchmarking and cross-comparison very difficult. "Open access" is extremely important and will require a change of business models.

Another discrepancy noted is the difference between the market management system and the operating software. It is important to have a uniform and consistent model for different grid operation applications. The modeling of loads with human factors would be extremely important. The interface of different software would be important. How to provide an integrated suite of software that would be able to solve many things from one program is a challenge.

An industry representative remarked once more on the importance of natural gas and power co-optimization. The co-optimization of transmission and distribution networks also would be very important.

On one hand, computing tasks would benefit greatly from cloud-based solutions. On the other hand, due to cybersecurity concerns, the power companies would not want to use public cloud computing for power system purposes. In this regard, it was suggested that the DOE national laboratories could play a crucial role in providing secure cloud-based solutions for the power industry.

PRESENTATIONS FROM THE AUDIENCE

Workshop participants were given the opportunity to give short presentations during the wrap-up session. Speakers were Yonghong Chen (Midcontinent ISO), Bita Analui (University of Vienna), Judy Cardell (Smith College), Michael (Misha) Chertkov (Los Alamos National Laboratory), Ranjit Kumar (InfSys LLC), Cynthia Rudin (Massachusetts Institute of Technology), and Terry Boston (PJM).

Yonghong Chen discussed the importance of mathematics and computations to companies such as Midcontinent ISO (MISO) and PJM. MISO has a footprint from Manitoba, Canada, to the Gulf of Mexico, and PJM is running the largest electricity market in the world. The centralized electricity market has brought significant benefits to society through the application of optimization and advanced policy analyses software, which can provide robust market solutions on 5-minute intervals. The industry is changing rapidly, and model complexity continues to increase. These models continue to push solvers (that rely on methods such as MIP) to their limits, and it is important that the mathematics community is engaged to address the performance challenges. While this workshop focused on the future grid, Chen noted that today's challenges—such as renewable integration, storage, increased demand response participation, increased uncertainty, and more decision variable within models—also require new solutions.

Bita Analui provided an alternative algorithmic approach for the robust integration of renewables into the energy system. Multistage stochastic optimization and modeling is an appropriate tool to combine the dynamic characteristics and stochastic parameters of real-world decision problems. An essential step in solving these problems is modeling reality in such a way that model solutions are appropriate and accurate enough to be used as real-world decisions. Analui explained that there are two ways to approach this modeling: (1) by using probability models, which give a description of the underlying uncertainty as random variables or random processes via probability distributions, or (2) by using scenario models, which are less complex, finite approximations of the probability models. In the real world, the true probability model is not known, and several models can represent the data equally well. This model uncertainty is usually ignored in stochastic optimization, and classical robust optimization considers only the worst-case scenario. Analui noted that a multistage distributionally robust approach could bridge this gap by taking into account the whole ambiguity set defined either parametrically or nonparametrically. The optimization problem can then be robustly solved by incorporating all the models rather than only one baseline model. This would quantify the cost of robustness, accounting for model uncertainty (Analui and Pflug, 2014).

Judy Cardell discussed the importance of privacy for demand response data, specifically with respect to the scope and duration of collected data (including the creation of new databases of personal data). She noted that there is and will be a market for these data. Some key considerations are the cultural and generational differences in privacy expectations and how much privacy can truly be protected. In an earlier breakout session, a participant also noted the importance of keeping privacy issues in mind because customers may be wary of handing over control of their appliances to a third party or utility. Another participant noted that designing mathematical models that preserve consumer privacy while utilizing sensitive data is a mathematical challenge.

Cardell described four different approaches to data collection:

1. Continue business as usual without any real-time pricing or demand response;
2. Allow appliances and HVAC demand response capability with one-way data flow, never collecting data;
3. Create privacy-aware design with two-way data flow, processing data at the source; or
4. Store all raw demand data flows in an ISO or aggregator, trusting that the data will not be misused.

She offered that the current market is jumping from option 1 to option 4, often overlooking the privacy concerns associated with the transition. She said that focusing on technology to facilitate options 2 and 3 would help protect current and future privacy concerns. If data are collected and the database is created, there will be a market for it from government, corporations, and aggregators. Privacy protections need to be designed into the emerging demand response framework. Cardell also noted that the solution space is very dependent on pricing framework (e.g., real-time pricing versus measuring interval consumption versus baselines).

Cardell concluded by discussing the analytic capabilities needed for one-way communication of reliability and price signals to customers and data processing at the source. One-way communication can be facilitated by end-use technologies such as smart plugs, GridWise, or home automation. However, it is difficult for an operator to best measure compliance without two-way communication. Data processing at the source ensures protection of private information to be anonymized while maintaining usefulness of data to the ISO or aggregator.

Michael (Misha) Chertkov discussed gas-grid reliability, grid sciences, and physics/grid machine learning. Chertkov noted that the power fleet is evolving, gas is becoming significant, and renewables are growing. He noted that the gas system is evolving as well, such as with the addition of the Transco pipeline; the increase in shale gas development; and improvements in flow reversals, liquefied gas, and storage. He noted that gas generation is growing because it is comparatively inexpensive and gas turbines can quickly respond to fluctuations, such as occur due to more renewables in the system. The current reality is that gas and electricity have two separate markets, but their interdependence limits reliability on both sides.

Chertkov called for new academic studies in operations (such as gas-flow awareness; generation dispatch; and stochastic, chance-constrained, and robust optimal power flow accounting for risks) and planning (such as regulations, reserves, liquefied gas, and gas storage especially for emergencies). He concluded by highlighting a few technical modeling challenges for the gas grid, specifically, line-pack gas dynamics, cost probabilities, mixing physics, statistics, optimization, and control.

Ranjit Kumar discussed the importance of voltage stability in a stable power grid. He provided the following references for more information: Kumar (2011, 2012); Kumar et al. (2011, 2012); Moslehi and Kumar (2010); and Moslehi et al. (2004, 2006a,b, 2008).

Cynthia Rudin discussed two case studies of machine learning for power grid reliability. The first case study is of reactive point processes (Ertekin et al., 2014), a statistical model derived from the New York City electric grid. Most reliability issues in New York City are due to the low-voltage secondary grid. Reactive point processes aim to provide short-horizon and real-time event prediction. It is a generative model for the past and can be used to simulate the future and decide what maintenance policies should be enacted. This is a very general, marked point process model. The model works by establishing baseline vulnerability, defined as the probability of failure at any given time. If an event happens, the probability rises for another event, and then the vulnerability slowly decreases over time. Similarly, if the secondary grid is inspected at a particular place and time, the probability of an event associated with that part of the system decreases, but it slowly rises back to the baseline vulnerability over time. The model has four key characteristics: it is saturating, self-exciting, self-regulating, and has a baseline adjustment. The model incorporates past history of inspections, number of cables at each inspection site, the ages of cables, inspections, etc., and is currently the best tool for predicting power failure in New York City (beating the Cox proportional hazard model and the current long-term prediction model).

The second case study Rudin discussed is the latent state hazard model (Moghaddass and Rudin, 2014). This model aims to predict failure by separating the latent (internal) vulnerability from vulnerability due to external sources using wind turbine data.

Terry Boston, from PJM, discussed the broad importance of improving the grid, specifically given the uncertainty that lies ahead. He highlighted the following ways that the grid may evolve over the coming decades:

- *High or low future growth.* There is a remanufacturing movement within the United States. Petrochemicals are moving into the Midwest through the use of liquid natural gas. Load forecasts are projected to increase from 0.5 to 3 percent, but some forecasts even call for a small decrease. The loads being forecast are different as well. Technology is improving to make energy use more efficient. For example, new refrigerators have variable-speed drive compressors that have very different load characteristics from what has been seen in the past.
- *Concentrated or highly diverse fuel portfolio.* The recent boom in production of combined-cycle generation facilities for natural gas implies a concentrated portfolio, but rooftop solar-distributed sources are on the rise.

With natural gas being so inexpensive, it is difficult for other technologies to compete.

- *Distributed self-supply by smaller units or centralized supply by large units.* The decentralized self-supply (e.g., solar) needs to be backed up by a centralized supply (e.g., gas). Currently, mostly large units supply generation, but Boston foresees a time when the generation and the customers are more integrated. This integrated grid with micro-grids that can be independent if needed will help improve security of the grid.
- *Autonomous micro-grid or central grid control.* Both will be important to improve stability and security of the grid.

Boston concluded by emphasizing the need for open-source software to improve flexibility, specifically to develop control systems that can focus on the integration of transmission, distribution, and generation. The physics and mathematics to do this exist, but the codes need to be developed.

7

Strategies Going Forward

CONCLUDING REMARKS

In the final workshop session, Robert J. Thomas (Cornell University) and J. Thomas Overbye (University of Illinois, Urbana-Champaign) concluded by noting that the electrical industry is vitally interested in getting its analytical methods right. The discussions provided throughout the workshop provided great insight into key areas of importance in data and data analytics, control optimization, and uncertainty.

WORKSHOP THEMES

Several topics were discussed on different occasions throughout the workshop. Points that were addressed by multiple speakers or participants during the course of the workshop include the following:

- *Renewable energy integration.* Several speakers (Bita Analui, Yonghong Chen, Steven Chu, and Pravin Varaiya) and breakout session participants discussed the importance and difficulty of integrating renewable energy into the grid. As distributed rooftop solar energy generation becomes increasingly prevalent, electrical providers need to find better ways to plan for and integrate these electricity sources. Chu discussed the possibility that individualized electricity storage for solar electricity (perhaps in the form of, or partnered with, electric vehicles) may help ease this transition. Another option discussed was increasing the prevalence of shorter-timescale markets in which renewables are able to more easily compete, compared to day-ahead markets.

- *Consumer energy storage.* Speakers (Steven Chu and David Sun) and breakout participants described the trend of some commercial and residential consumers moving to distributed personalized energy storage. As Chu discussed, this can come in the form of a large heat and power system, such as what is currently available at Texas Medical Center, or in the form of smaller individualized electricity storage for solar electricity (perhaps in the form of, or partnered with, electric vehicles).
- *Aged transmission and distribution infrastructure.* The current transmission and distribution system was described as being outdated (Steven Chu and Louis Wehenkel) and often relying on failing infrastructure that has surpassed its planned life span.
- *Open-source software.* A lack of open-source software was discussed by speakers Terry Boston and Matthew Gardner and breakout session participants. Gardner stated that increased use of, and comfort with, open-source solutions could help utilities update outdated models in multiple areas, and some breakout session participants stated that such a move could help engage a broader research community.
- *Sharing data.* Several speakers (Judy Cardell, Steven Chu, Matthew Gardner, and Louis Wehenkel) and breakout session participants discussed the need to share data responsibly both between utility providers and researchers. Data of particular interest are those from phasor measurement units. Wehenkel commented that more data need to be available, especially for estimation of the remaining lifetime of transmission system assets and the estimation of joint probabilities of multiple faults. Cardell and breakout session participants emphasized the need to consider consumer privacy while designing and deploying new technology.
- *Evolving business models.* Many speakers (Terry Boston, Michael Chertkov, Steven Chu, David Sun, and Pravin Varaiya) and breakout participants discussed the changing paradigm of the grid in the context of what it means for utility companies. Chu's description was that as consumers move toward more rooftop solar, electric vehicles become commonplace, and large stationary batteries become widely available, more and better pricing and generation models are deployed and other alternatives, such as switching to a personalized gas generator, become more popular—compelling utilities to examine what this means for their current business models and how they will adapt. Sun believes that utility companies will adapt by unbundling existing services and offering new, more innovative services to consumers. Varaiya suggested that a potentially viable option

would be for utilities to modify their approach to meeting the flexible demands of consumers through means such as priority pricing, interruptible electrical power, demand response, price-responsive demand, and duration-differentiated energy service. The possibility of increased reliance on high-voltage direct-current technologies as a way to better transport electricity was also discussed.

- *Security.* The importance of protecting the grid from cyber and physical attacks was discussed by several speakers (Terry Boston, Steven Chu, and Matthew Gardner) and in multiple breakout sessions. This was a notable concern when discussing grid control architecture.
- *Moving to a smart grid.* Transitioning from a legacy grid to a smart grid was discussed throughout the workshop by many speakers (Steven Chu, Sean Meyn, David Sun, Pravin Varaiya, and Louis Wehenkel) and breakout session participants. Chu noted that this will require the use of more modern technology, better models, and nimble electricity generators and providers. Sun discussed several demonstration projects (e.g., NiceGrid and the Pacific Northwest Demonstration Project) that will offer lessons for larger transitions to come, and Wehenkel discussed some of the innovations that would need to happen across the grid. Varaiya described some consumer-oriented approaches to modifying demand instead of load. Meyn discussed the importance of eliminating risk to consumers and the grid when using demand-side flexibility for reliable ancillary services in a smart grid.
- *Improved modeling needed.* The role for mathematical and computational modeling is increasing, as explained by multiple speakers (Bita Analui, Robert Bixby, Yonghong Chen, Michael Chertkov, Steven Chu, Alexander Eydeland, Matthew Gardner, Miriam Goldberg, Sean Meyn, Cynthia Rudin, David Sun, and Louis Wehenkel) and breakout session participants. These include optimization models (such as linear programming and mixed-integer programming), dynamic game theory and mechanism design, power-flow models, human-in-the-loop models, nonlinear control and stability models, statistical models that represent observational data via probability densities (such as Gaussian processes, Markov chains/fields, logistic models, random forests, and support vector machines), physical models that represent deterministic constraints among physical quantities (such as algebraic and differential equations), consumer behavior and response models (for systems such as real-time pricing, priority pricing, interruptible electrical power, demand response, price-responsive demand, deadline-differentiated service, and duration-differentiated energy service), uncertainty analysis, causal analysis, and power market pricing (such as Black-Scholes theory).

- *Uncertainty.* The importance of understanding uncertainty in models and physical systems was discussed by Yonghong Chen and Miriam Goldberg and in breakout sessions. Goldberg described the three main kinds of measurement and verification uncertainties in grid modeling: estimation/forecasting error, policy choices and conventions, and extrapolations.

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Appendixes

A

Registered Workshop Participants

Abed, Eyad – University of Maryland
Aceves, Alejandro – Southern Methodist University
Ambrosio, Ron – IBM
Analui, Bita – University of Vienna
Anderson, Lindsay – Cornell University
Armbruster, Dieter – Arizona State University
Bitar, Eilyan – Cornell University
Bixby, Robert – Gurobi Optimization
Bose, Anjan – Washington State University
Boston, Terry – PJM Interconnection, LLC
Cardell, Judy – Smith College
Carvalho, Rui – University of Cambridge
Castaneda, Juan – Southern California Edison
Chen, Yonghong – Midcontinent ISO
Chertkov, Michael – Los Alamos National Laboratory
Chu, Steven – Stanford University
Crane, Alan – National Academies of Sciences, Engineering, and Medicine
Dagle, Jeffery – Pacific Northwest National Laboratory
Dominguez-Garcia, Alejandro – University of Illinois
Eto, Joseph – Lawrence Berkeley National Laboratory
Eydeland, Alexander – Morgan Stanley
Gardner, Matthew – Dominion Virginia Power
Gee, Matthew – University of Chicago

Glassman, Neal – National Academies of Sciences, Engineering, and Medicine
Goldberg, Miriam – DNV GL
Guckenheimer, John – Cornell University
Howard, Rodney – National Academies of Sciences, Engineering, and Medicine
Ilic, Marija D. – Carnegie Mellon University
Jones, Wesley – National Renewal Energy Laboratory
Kelly, Frank P. – University of Cambridge
Kevrekidis, Yannis G. – Princeton University
Kumar, Ranjit – InfSys LLC
Lesieutre, Bernie – University of Wisconsin, Madison
Meliopoulos, Sakis – Georgia Institute of Technology
Meyn, Sean – University of Florida
Meza, Juan C. – University of California, Merced
Mezic, Igor – University of California, Santa Barbara
Moore, Richard Taplin – National Academies of Sciences, Engineering, and Medicine
Moslehi, Khosrow – ABB, Inc.
Mukerji, Rana – New York Independent System Operator
Overbye, Thomas – University of Illinois, Urbana-Champaign
Pai, Anantha – University of Illinois
Panciatici, Patrick – Réseau de Transport d'Electricité
Rudin, Cynthia – Massachusetts Institute of Technology
Saari, Donald – University of California, Irvine
Sankar, Lalitha – Arizona State University
Scaglione, Anna – University of California, Davis
Schwalbe, Michelle – National Academies of Sciences, Engineering, and Medicine
Sherick, Robert – Southern California Edison
Stoustrup, Jakob – Pacific Northwest National Laboratory
Sun, David – Alstom
Taylor, Jason – Electric Power Research Institute
Thomas, Robert – Cornell University
Tong, Lang – Cornell University
VanVleck, Erik – University of Kansas
Varaiya, Pravin – University of California, Berkeley
Waligorski, Joe – FirstEnergy Corp.
Wang, Congcong – Midcontinent ISO
Watson, Jean-Paul – Sandia National Laboratory
Wehenkel, Louis – University of Liege, Belgium
Weidman, Scott – National Academies of Sciences, Engineering, and Medicine
Wierman, Adam – California Institute of Technology
Xie, Le – Texas A&M University
Zhu, Hao – University of Illinois

B

Workshop Agenda

DAY 1: FEBRUARY 11, 2015

8:00 a.m. **Welcome, Introductions, and Overview**

Opening Remarks and Meeting Overview
Robert J. Thomas, Cornell University, Workshop Planning Committee Chair

Welcome and Study Objectives
John Guckenheimer, Cornell University, Study Committee Co-Chair
Thomas J. Overbye, University of Illinois, Urbana-Champaign, Study Committee Co-Chair

8:15 **Keynote: Setting the Stage**

Low-Cost Pathways to Grid Integration of Renewable Energy: Skating to Where the Puck Is Going to Be
Steven Chu, Stanford University

9:15	**Data and Data Analytics** *Session Co-Chairs: Cynthia Rudin, Massachusetts Institute of Technology, and Marija Ilic, Carnegie Mellon University*
	Prosumer-Centric Power Industry Transformation *David Sun, Alstom*
	How to Combine Observational Data Sources with First Principles of Physics to Build Stable and Transportable Models for Power System Design and Control *Louis Wehenkel, University of Liege, Belgium*
	Grid Scale Data Fusion: Obstacles and Opportunities *Matthew Gardner, Dominion Virginia Power*
12:00 p.m.	**Breakout Session**
2:00	**Optimization and Control Methods for a Robust and Resilient Power Grid** *Session Chair: Jeffery Dagle, Pacific Northwest National Laboratory*
	Duration-Differentiated Electric Service for Integrating Renewable Power *Pravin Varaiya, University of California, Berkeley*
	Demand-Side Flexibility for Reliable Ancillary Services in a Smart Grid: Eliminating Risk to Consumers and the Grid *Sean Meyn, University of Florida*
	Advances in Mixed-Integer Programming and the Impact on Managing Electrical Power Grids *Robert Bixby, Gurobi Optimization*
4:45	**Breakout Session**

DAY 2: FEBRUARY 12, 2015

8:30 a.m. **Uncertainty Quantification and Validation**
Session Chair: Juan C. Meza, University of California, Merced

How Well Can We Measure What Didn't Happen and Predict What Won't?
Miriam Goldberg, DNV GL

Mathematical Models in Power Markets
Alexander Eydeland, Morgan Stanley

10:30 **Breakout Session**

11:45 **Wrap-Up Session**
Session Chair: Robert J. Thomas, Cornell University

Presentations from the audience

12:30 p.m. **Final Remarks by the Organizers**

1:00 **Workshop Adjourns**

C

Acronyms

AC	alternating current
ACM	adaptive constrained model
AGC	automatic generation control
AGM	Adaptive Generator Model
AHU	air handling unit
AIMMS	Advanced Interactive Multidimensional Modeling System
AS	ancillary service
BPA	Bonneville Power Authority
CAE	control area expansion
CBP	cost-based pool
CO	commercial operation
COP	current operating plan
DA	day ahead
DC	direct current
DD	duration-differentiated
DER	distributed energy resource
DMS	distribution management system
DOE	Department of Energy
DP	dynamic priority
DR	demand response

DSO	distribution system operator
EFOR	equivalent forced outage rate
EHV	extra high voltage
EIA	Energy Information Administration
EMS	energy management system
EPRI	Electric Power Research Institute
ESCAPE	European Study of Cohorts for Air Pollution Effects
FACTS	flexible alternating current transmission system
FERC	Federal Energy Regulatory Commission
FTR	financial transmission right
GARPUR	Generally Accepted Reliability Principle with Uncertainty Modelling and through Probabilistic Risk Assessment
GBM	geometric Brownian motion
GCA	generation control application
GSU	generator step-up unit
HVAC	heating, ventilation, and air conditioning
HVDC	high-voltage direct-current
IEEE	Institute of Electrical and Electronics Engineers
ISO	independent system operator
IT SCED	intermediate security constrained economic dispatch
LLDF	longest leftover duration first
LMP	locational marginal pricing
LNG	liquefied natural gas
LP	linear programming
LR	Lagrangian relaxation
LV	low voltage
M&V	modeling and verification
MC	market control
MCE	market clearing engine
MCP	marginal clearing price
MDB	market database
MIP	mixed-integer programming
MISO	Midcontinent Independent System Operator
MMS	market management system

MOI	market operator interface
MPI	Market Participant Index
MSS	Market Settlements Subcommittee
MV	medium voltage
NASA	National Aeronautics and Space Administration
NEI	Nuclear Energy Institute
NEM	National Electricity Market
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
OE	Office of Electricity Delivery and Energy Reliability (within the Department of Energy)
PDE	partial differential equation
PDR	price responsive demand
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric
PHEV	plug-in hybrid electric vehicle
PMU	phasor measurement unit
PNNL	Pacific Northwest National Laboratory
PO	physical operation
PPA	power purchase agreement
PV	photovoltaic
QoS	quality of service
RIPS	Resilient Interdependent Infrastructure Processes and Systems
RPM	reliability pricing model
RPS	renewable portfolio standard
RT	real-time
RT SCED	Real-Time Security Constrained Economic Dispatch
RTDMS	Real Time Dynamics Monitoring System
RTP	real-time pricing
SB	sequential bidding
SCADA	supervisory control and data acquisition
SCUC	security-constrained unit commitment
SFT	simultaneous feasibility test
SOC	service organization control

SPP	Southwest Power Pool
SVM	support vector machine
T&D	transmission and distribution
TSO	transmission system operator
UDS	unit dispatching system
VFD	variable frequency drive