# Appendix A

# Metrics for the Smart Grid System Report

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# Metrics for the Smart Grid System Report

# Introduction

This appendix presents papers covering each of the 21 metrics identified in Section 2.1. These metric papers were prepared in advance of the main body of the report and collectively form its informational backbone. The list of metrics is derived from the material developed at the 2008 Smart Grid Implementation Workshop and refined through the development of this report. The objective of the metric development process was to distill the best ideas into a small number of metrics with a reasonable chance of successful measurement and assessment.

The metrics examined in this appendix are of two types: build metrics that describe attributes that are built in support of the smart grid, and value metrics that describe the value that may be derived from achieving a smart grid. Build metrics generally lead the value that is eventually provided, while value metrics generally lag in reflecting the contributions that accrue from implementations. While build metrics tend to be quantifiable, value metrics can be influenced by many developments and therefore generally require more qualifying discussion. Both types are important in describing the status of smart grid implementation.

Each metric paper is divided into five sections as outlined below:

- Introduction and Background: A brief introduction to the concepts addressed by the metric, including an overview of relevant issues.
- Description of Metric and Measurable Elements: An identification and description of the metric being evaluated.
- Deployment Trends and Projections: The current status of the metric, analysis of trends and projections, identification of relevant stakeholders and their relationship to the smart grid, and assessment of regional influences on smart grid deployment.
- Challenges to Deployment: An overview of the technical, business, and financial challenges to smart grid deployment.
- Metric Recommendations: Recommendations to consider when preparing the next Smart Grid System Report to Congress.

The content in these metric papers is summarized in sections of the main body of the report. References embedded in the report are included to enable readers to trace content back to its source here in Appendix A.

# A.1 Metric #1: The Fraction of Customers and Total Load Served by Real-Time Pricing, Critical Peak Pricing, and Time-of-Use Pricing

## A.1.1 Introduction and Background

Historically, service providers have set prices on a flat-rate basis, unaffected by the time the energy is used by customers or by the time-varying cost to the operator to supply the energy. The flat-rate system, while simple to understand and communicate to customers, does lead to overconsumption of energy during peak periods when the cost to supply the power is at its highest point. Smart grid implementation allows transition from a traditional flat-rate pricing scheme to more flexible rate options such as time-of-use pricing (TOU), critical-peak pricing (CPP) and real-time pricing (RTP). Implementation of such tariffs has been forecast to offset between 38,000 and 82,000 megawatts (MW), or 4 to 9 percent of United States (U.S.) peak electricity demand by 2019.[1]

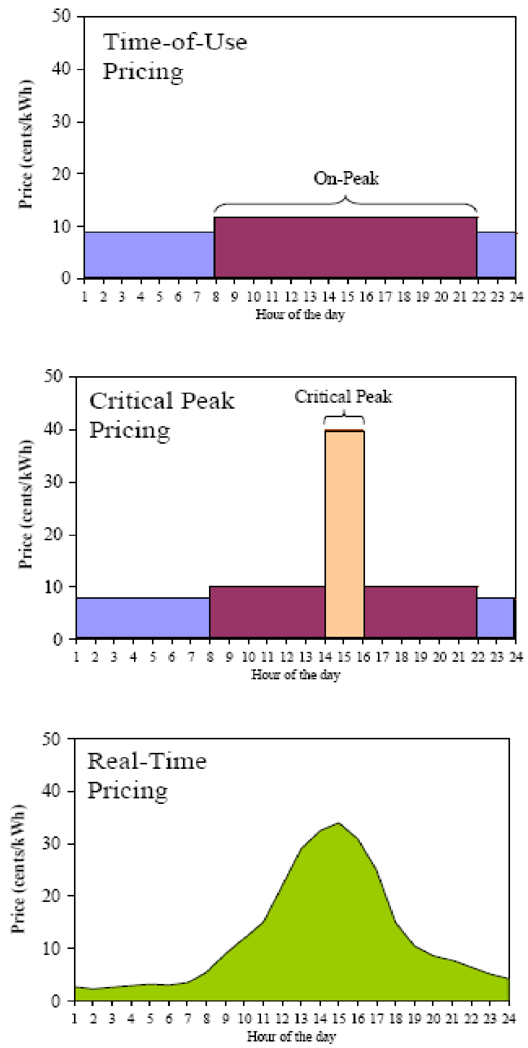


**Figure A.1**. Examples of Dynamic Pricing Tariff Structures

There are three principal pricing or tariff types covered in this section, as presented in Figure A.1.[2] TOU tariffs incentivize customers to permanently alter their energy consumption by using static price rates that are different during peak and off-peak periods. In contrast to a static system, implementation of Advanced

[1] FERC – Federal Energy Regulatory Commission. 2010. *National Action Plan on Demand Response.* Docket No. AD09-10, June 17, 2010. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf (undated webpage).

[2] FERC – Federal Energy Regulatory Commission. 2008. *Assessment of Demand Response and Advanced Metering.* Staff Report, Docket Number AD-06-2-000, December 2008. Federal Energy Regulatory Commission, Washington, D.C. Accessed November 6, 2008 at http://www.ferc.gov/legal/staff-reports/demand-response.pdf (undated webpage).

Metering Infrastructure (AMI) and other demand-side equipment allows utilities to move toward demand-response tariffs such as CPP and RTP, which incorporate dynamic pricing structures that can be monitored and changed in intervals[3] such as 15 minutes. CPP tariffs are designed to adjust rates during higher critical-peak periods, but are limited to a small number of hours (e.g., 100 of 8,760) each year, with the peak price being much higher than during normal conditions. Under RTP, prices vary at hourly or even shorter intervals, based on the day-of (real-time) or day-ahead cost of power to the service provider. Prices fluctuate throughout the day, with the highest prices set during peak periods. RTP tariffs are the most dynamic of the three pricing structures and are, therefore, most dynamically responsive to peak-period consumption and energy costs. Adoption of dynamic pricing tariffs is designed to be revenue neutral for utilities, meaning an increase of the retail electricity price during peak periods would be offset by a decrease in price during off-peak times.

### A.1.2 Description of Metric and Measurable Elements

(Metric 1.a) The fraction of customers served by RTP, CPP, and TOU tariffs.

(Metric 1.b) The fraction of load served by RTP, CPP, and TOU tariffs.

### A.1.3 Deployment Trends and Projections

RTP tariffs have historically been offered on either a voluntary or default (mandatory) basis, and primarily to industrial and large commercial accounts. The Federal Energy Regulatory Commission (FERC) conducted interviews about demand-response and advanced-metering initiatives in 2008. The FERC questionnaire was distributed to 3,407 organizations in all 50 states. In total, 100 electricity service providers that participated reported offering some form of RTP tariff to enrolled customers, as compared to 60 in 2006 (Table A.1). FERC also found through these interviews that 315 electric service providers nationwide offered TOU rates, compared to 366 in 2006. In those participating utilities, approximately 1.3 million electricity consumers were signed up for TOU tariffs, representing approximately 1.1 percent of all residential, commercial and industrial customers (Table A.1). In 2008, customers were enrolled in CPP tariffs offered by 88 entities, as compared to 36 in 2006. No studies were found that estimated the total number of customers served by RTP and CPP tariffs. No data has been found supporting Metric 1b; however, FERC estimated the reduction in peak demand through demand response to be 37 gigawatts (GW) in 2009.[4]

[3] FERC – Federal Energy Regulatory Commission. 2009. *A National Assessment of Demand Response Potential.* Staff Report, June 2009. Prepared by The Brattle Group; Freeman, Sullivan & Co.; and Global Energy Partners, LLC for the Federal Energy Regulatory Commission, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf (undated webpage).

[4] FERC 2009.

**Table A.1**. Number of Entities Offering and Customers Served by Dynamic Pricing Tariffs[5]

| Method of Pricing | Number of Entities in 2006 | Number of Entities in 2008 | Customers Served | |
|---|---|---|---|---|
| | | | Number | Share of Total |
| Real-Time Pricing | 60 | 100 | -- | -- |
| Critical-Peak Pricing | 36 | 88 | -- | -- |
| Time-of-Use Pricing | 366 | 315 | 1,270,000 | 1.1% |

In 2009, FERC required regional transmission operators (RTOs) and independent system operators (ISOs) to take actions to ensure comparable treatment of demand-response resources.[6] Since these new requirements were adopted, PJM, Independent System Operator – New England (ISO-NE), New York Independent System Operator (NYISO), Midwest ISO, California Independent System Operator (CAISO), and Southwest Power Pool Inc., have submitted proposals for redesigned market structures that will incorporate dynamic pricing tariffs. Currently, 31,695 MW of demand response (dynamic pricing, direct load control, and interruptible tariffs) is available in ISO and RTO markets, which represents 6.6 percent of 2008 peak electricity demanded within the combined regions; a potential of up to 14 to 20 percent of peak demand is forecast.[7]

For this report, interviews were conducted with 24 municipal, public, investor owned and nonprofit service providers (see Appendix B). The companies were asked two questions relevant to dynamic pricing. The first question asked respondents: Do you have dynamic or supply-based price plans?

- Twelve companies (50 percent) indicated no dynamic price plans were in place.
- Twelve companies (50 percent) indicated they had TOU plans.
- No companies (0 percent) offered CPP plans.
- One company (4.2 percent) offered RTP (on order of minute up to hour).

The companies were also asked whether they had automated response-to-pricing signals for major energy-using devices within a premise. The responses were:

- Fifteen companies (62.5 percent) indicated there were none.
- Seven companies (29.2 percent) indicated that automated price signals for major energy-using devices were in the development stage.
- Two companies (8.3 percent) indicated that a small degree of implementation (10 to 30 percent of the customer base) had occurred.

[5] FERC 2008.
[6] FERC 2010.
[7] FERC 2010.

When RTP tariffs were initially offered in the 1980s, customers were typically charged an hourly varying price quoted on a day-ahead basis. The prices for generation, transmission, distribution, and ancillary services were bundled into a single price. Rate structures were designed to be revenue neutral. Customers, however, were not entirely shielded from price volatility. Customers included in early RTP programs were medium and large commercial and industrial customers.

In the 1990s, RTP programs shifted increasingly toward a two-part system where customers faced standard pricing up to a customer baseline load (CBL), which had been established on historical consumption patterns, and a higher peak price for power purchased in excess of CBL levels. Load reductions below CBL levels resulted in a bill credit. In recent years, the CBL two-part design has become less common and utilities have shifted toward greater retail competition and have offered unbundled RTP tariffs with day-ahead notification. The programs target all commercial and industrial customers and, on a pilot basis, some residential customers.

Electricity service provider investment supporting RTP, CPP, and TOU pricing has increased since the American Recovery and Reinvestment Act (ARRA) in 2009, which allocated $3.4 billion in grants to invest in smart grid technologies and electricity transmission infrastructure, with total investment of $8.2 billion.

In 2008, the Pacific Gas and Electric Company (PG&E) began their residential SmartRate program, which offered voluntary CPP tariffs to approximately 10,000 customers. By the end of 2009, over 25,000 customers had signed up for the program.[8] The program raised rates incrementally during the afternoon peak period (2 p.m. to 7 p.m.) up to as high as $0.60 per kilowatt-hour (kWh) for residential customers and $0.75 per kWh for non-residential customers.[9] The results of the program indicate that the incrementally higher rates resulted in reductions in peak-period energy use by an average of 15 percent by residential customers and 7.5 percent by low-income residential customers; average load reductions increased to 19.2 percent when customers were successfully notified of the event.[10] Participants were offered bill protection, credits, and financial incentives (gift cards) for enrollment.

The first large-scale RTP pilot program was initially conducted by the Community Energy Cooperative, and then completed by Commonwealth Edison throughout Illinois between 2003 and 2006. On the highest-price notification day in 2005, customers reduced their energy

[8] George S, J Bode, M Perry, and Z Mayer. 2010. *2009 Load Impact Evaluation for Pacific Gas and Electric Company's Residential SmartRate™—Peak Day Pricing and TOU Tariffs and SmartAC Program*. Prepared for the Pacific Gas and Electric Company by Freeman, Sullivan & Co. Accessed November 3, 2010 at http://www.calmac.org/publications/2009_PGE_SmartRate_SmartAC_and_Residential_TOU_Evaluation_Final_-_Volume_I_(Ex-Post).pdf (undated webpage).

[9] George et al. 2010.

[10] George et al. 2010.

demand by 15 percent, and their overall net energy consumption during the summer decreased 3 to 4 percent.[11] Although residential pilot programs continue to be conducted and quantified, benefits of current RTP programs tend to be highest within the commercial and industrial sectors.

### A.1.4 Associated Stakeholders

There are a number of stakeholders with interest in the dynamic pricing of electricity:

- Regulatory agencies considering AMI business cases and dynamic pricing programs.
- Residential, commercial, and industrial end users who could benefit financially through the deployment of RTP programs, but must overcome their aversion to risk while processing sufficient information to fully understand the benefits and complexity of dynamic pricing programs.
- Electric-service retailers who need to carry out dynamic pricing programs. They need access to wholesale markets that allow them to structure incentive programs to consumers that offer them the means for a viable business model. They desire a level of consistency across the nation so the service offering can be replicated and efficiencies shared.
- Distribution-service providers who could use dynamic pricing adders to address capacity issues, increase reliability, and utilize their assets more fully.
- Balancing authorities (BAs) and reliability coordinators who could use dynamic prices to mitigate congestion issues and address planned or unplanned shortfalls in available generation capacity.
- Wholesale electricity traders and market operators who can use price elasticity to balance supply and demand, providing for a more responsive energy market.
- Products and services suppliers who are interested in providing the metering, communications, and interfaces with demand-side automation to support dynamic pricing programs.
- Standards organizations, which need to attract stakeholders to develop and adopt standards for the interfaces between the technologies being selected to support dynamic pricing programs.
- Policy advocates, including environmental organizations, who can benefit from dynamic pricing to provide alternatives for new-generation power plants and transmission, and consumer groups that want to mitigate price increases.

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[11] Faruqui A, S Sergici, and L Wood. 2009. *Moving Toward Utility Scale Deployment f Dynamic Pricing in Mass Markets*. IEE Whitepaper, Institute for Electric Efficiency, Washington, D.C. Accessed October 8, 2010 at http://www.edisonfoundation.net/iee/reports/IEE_Utility-ScaleDynamicPricing_0609.pdf (undated webpage).

- Policy makers who see dynamic pricing as a way to foster competitive markets and manage load while reducing the need to expand existing generation, transmission, and distribution infrastructure. They are concerned that consumers are treated equitably and will be better off with dynamic pricing than with the traditional flat-rate tariff.

### A.1.5 Regional Influences

States with demand-response, load-management, and electricity-efficiency programs as of 2009 are indicated in Figure A.2. Although states identified in blue all have demand-response programs available, FERC has noted there is a significant gap between 2009 levels and the potential of full deployment. FERC results also suggest that California, Florida, and New England have significant demand response activity, while Alaska, Montana, and Wyoming have very little. Overall, market effects of dynamic pricing are still insignificant; FERC estimates that penetration in ten states is 1 percent or less, and only one state is estimated to have 2 percent penetration.[12]

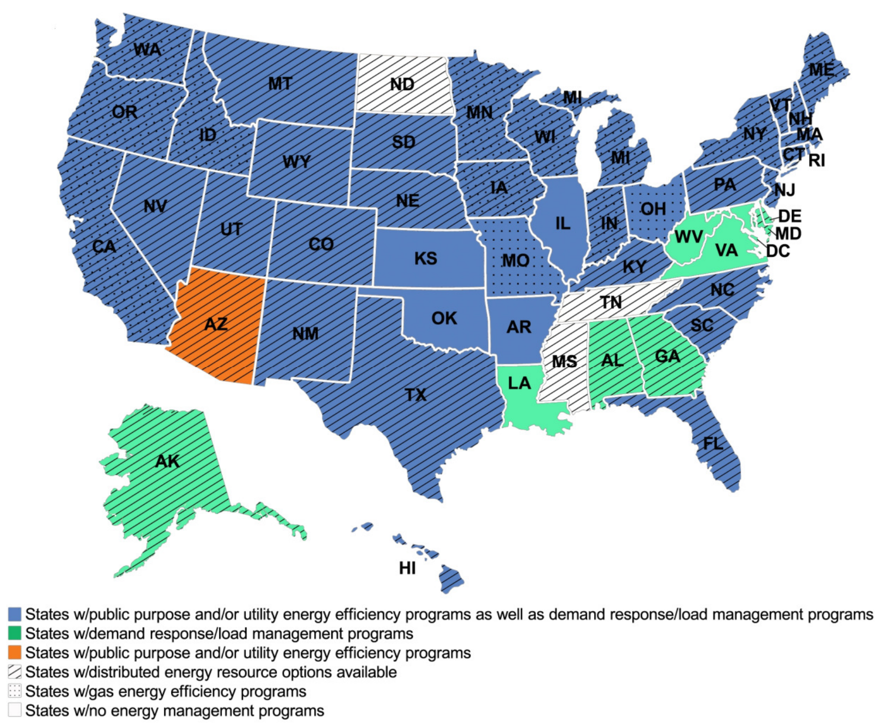


**Figure A.2**. States with Demand Response, Load Management, and Energy Efficiency Programs[13]

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[12] FERC 2010.

[13] DOE – U.S. Department of Energy. 2009. *Energy Incentive Programs*. U.S. Department of Energy, Washington, D.C. Accessed July 10, 2010 at http://www1.eere.energy.gov/femp/financing/energyincentiveprograms.html (last updated October 26, 2009).

### A.1.6 Challenges to Deployment

The remainder of this section outlines a number of technical and business/financial barriers to implementing dynamic pricing in the energy sector.

### A.1.7 Technical Challenges

Technical barriers include those related to AMI, other infrastructure requirements, and the need to update billing systems. Utilities must be able to measure usage according to the programs offered, communicate pricing information, and update billing systems prior to deploying variable pricing programs. Although smart meter deployment has increased since 2008, there is still a lack of AMI infrastructure, including communications systems and other enabling technologies. Additionally, hardware and software applications are necessary to handle dynamic pricing and AMI, allowing consumers and service providers to communicate with each other and respond to dynamic tariffs.

### A.1.8 Business and Financial Challenges

Financial and customer-perception barriers include the following:

- There are significant costs to service providers when installing AMI and updated billing systems. Regulatory recovery of these costs can be a contentious issue (see Metric 4). Focusing on large industrial customers and commercial buildings reduces the cost on a per-MW basis.
- The regulated retail market can be a challenge to third-party electricity aggregators and service providers, who desire access to customers and dynamic pricing markets that can support viable business plans.
- Quantitative assessments of customer responsiveness to prices are limited. Thus, effects on service provider finances are not well understood prior to program deployment.
- There may be a self-selection bias in voluntary programs as customers who use less power during peak periods are more likely to enroll in the program, thus having less effect on load participation.
- Customers are not typically interested in complex dynamic pricing programs that must be monitored on an hourly or daily basis. Participation in most voluntary RTP programs has declined in recent years. However, with installation of automated controllers or automated agents, customers could anticipate and take advantage of price changes to reduce their energy costs.
- Energy consumers are often averse to risk, and the assistance now offered by most service providers to protect them from price volatility may be perceived as inadequate.

- There may still be much uncertainty about what price level would be enough to draw consumers to dynamic pricing simply because consumers must find it worthwhile to take the extra effort to set up their system to take advantage of dynamic pricing. Longer duration studies are needed that evaluate the quality and quantity of data, and the price levels needed to entice consumer response.

### A.1.9 Metric Recommendations

Future reports should consider breaking down the metric by customer type (e.g., residential, industrial, commercial) to provide greater clarity into consumer response to dynamic tariffs. In addition, data are needed to measure the fraction of load served by dynamic pricing as outlined in Metric 1.b. A reporting system designed to address this issue should be considered for future dynamic pricing metrics.

# A.2 Metric #2: Real-Time System Operations Data Sharing

## A.2.1 Introduction and Background

A grid that is "smart" engages information technology in the operation of the transmission grid as much as it does in the distribution network. The foundation of any smart grid network is inherently the data and information that drive the applications that, in turn, enable new and improved operational strategies to be deployed. Data collected at any level of the system, from customer metering to distribution, transmission, generation, and market operations, may be pertinent to improving operations at any other level. Thus, sharing data in a timely fashion, in near-real time, with all those with a need or right to know, is an essential ingredient of a smart grid.

This section addresses a metric for increased levels of real-time data sharing. Real-time here means operational updates on time scales that may vary from sub-second to a few minutes. This metric focuses on sharing data between parties at the level of bulk transmission grid operations, as opposed to sharing information within an electricity service provider, or for engaging demand response or distribution-system level operations such as operating distributed generation and storage.

Within an electricity service provider's operations footprint, it can be reasonably assumed that data are shared, or could be shared, to the extent required to maintain system stability and reliability, within statutory limits separating transmission operations and wholesale-power-marketing activities.[14] That is, the "right to know" within the electricity service provider is implicit, and sharing data within the electricity service provider is limited primarily by the difficulty and cost of connecting applications to sensor networks and databases.

### A.2.1.1 Explanation of Reliability Coordination Versus Balancing Authority Responsibilities

A balancing authority (formerly known as a control area) is defined by the North American Electric Reliability Corporation (NERC) functional model as an entity that regulates system frequency and performs other coordination activities based on field measurements and external data from neighbors and the appropriate reliability coordinator (RC). BAs must maintain the grid's physical integrity and adhere as closely as possible to the agreed-upon

[14] FERC – Federal Energy Regulatory Commission. FERC Order No. 888: Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities. Federal Energy Regulatory Commission, Washington, D.C. Accessed November 3, 2008 at http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp (last updated May 25, 2006).

schedule for dispatch of generation, imports, and exports. RCs are needed to coordinate the actions of BAs to maintain overall system reliability. The transmission grid has been increasingly utilized to transfer wholesale power long distances, something which neither its physical design nor its management systems were built to support.

Figure A.3 illustrates the NERC Reliability Coordinator List: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), Reliability First Corporation (RFC), Southeast Reliability Corporation (SERC), Southwest Power Pool (SPP), Texas Regional Entity (TRE), and Western Electricity Coordinating Council (WECC).

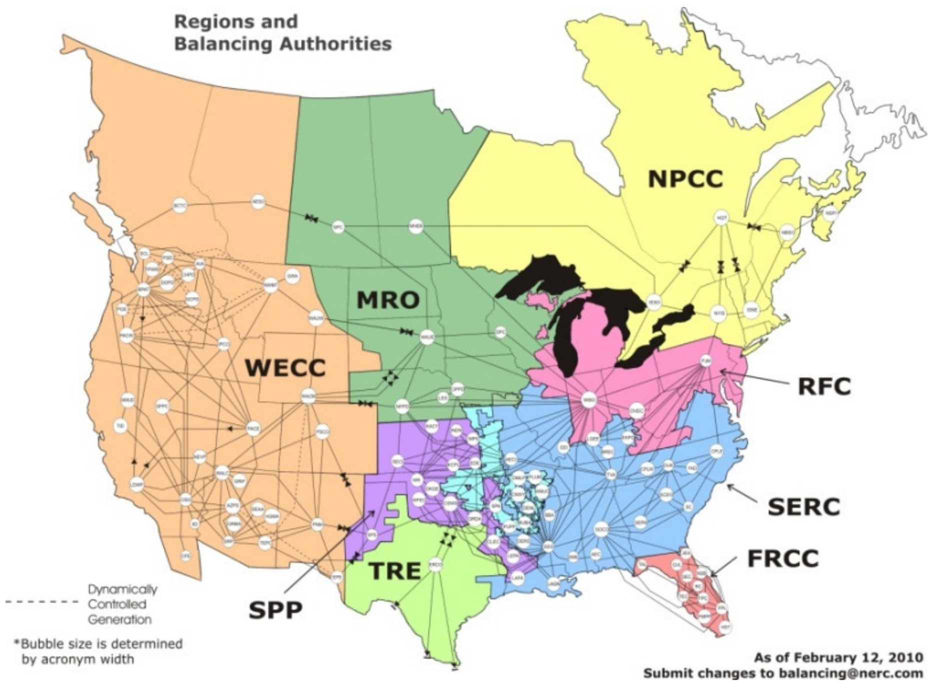


**Figure A.3**. NERC Reliability Coordinator and Balancing Area Map[15]

### A.2.1.2 Historic Drivers for Improving Real-time Data Exchange

Two wide-area blackouts in the western interconnection in 1996[16] and the 2003 blackout in the eastern interconnection[17] showed how problems that originated in one area of the grid

[15] NERC – North American Electric Reliability Corporation. 2010a. *Regions and Balancing Authorities*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed October 21, 2010 at http://www.nerc.com/docs/oc/rs/BA_BubbleDiagram_2010-02-12.jpg (last updated February 12, 2010).

[16] NERC – North American Electric Reliability Council. 2002. *1996 System Disturbances: Review of Selected 1996 Electric System Disturbances in North America*. North American Reliability Council, Princeton, New Jersey. Accessed November 3, 2008 at http://www.nerc.com/files/disturb96.pdf (undated webpage).

[17] U.S.-Canada Power System Outage Task Force. 2004. *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations.* Accessed November 3, 2008 at https://reports.energy.gov/BlackoutFinal-Web.pdf (undated webpage).

could cause blackouts in other widely dispersed areas, and with no way for the adjacent operators to see the problem coming or limit the damage of the disturbance. A report conducted jointly between the U.S. Department of Energy (DOE) and the FERC after the 2003 blackout concluded the event was caused partly by system deficiencies and a lack of awareness of deteriorating conditions by the operators who monitor the system. The report also found that technology existed that could have been used for real-time monitoring, thus improving reliability, and new technologies could enhance system integrity and improve operator awareness, consequently reducing the potential for future blackouts.[18] DOE/FERC concluded that an interconnection-wide monitoring system could be beneficial by providing real-time Supervisory Control and Data Acquisition (SCADA) system data, and could potentially standardize data storage and visualization features so all operators/dispatchers could access common information.[19]

#### A.2.1.3 Implementation of Interconnection-Wide (Western, Eastern, and Electric Reliability Council of Texas [ERCOT]) Transmission Monitoring

On a practical basis SCADA data will be supplemented as phasor data (i.e., synchrophasor measurements) are obtained from phasor measurement units (PMUs) capable of high-time-resolution (typically 30 samples per second) measurements of voltage and current waveforms, time synchronized and time stamped using the satellite-based global positioning system. Phasor data supplements SCADA data. The current applications that use phasor data do not require the same comprehensive coverage provided by SCADA. Data are currently registered from a relatively sparse network of PMUs, but will grow quickly due to ARRA funding (877 PMUs funded by ARRA versus less than 200 PMUs prior to funding). PMUs are being used to provide situational awareness and early warning of stability and reliability issues, as well as post-event forensic capabilities for wide areas of the grid.

Eventually, more-comprehensive reliability analysis tools will be based on broadly sharing data and may lead to increased utilization of wide-area control schemes and remedial-action schemes, allowing dynamic adjustment, depending on the state of the grid. This would allow realization of self-healing functions that have long been a key goal of the smart grid at the transmission level.

[18] DOE and FERC – U.S. Department of Energy and the Federal Energy Regulatory Commission. 2006. *Steps to Establish a Real-Time Transmission Monitoring System for Transmission Owners and Operators Within the Eastern and Western Interconnections: A Report to Congress Pursuant to Section 1839 of the Energy Policy Act of 2005*. U.S. Department of Energy and the Federal Energy Regulatory Commission, Washington, D.C. Accessed October 21, 2010 at http://www.oe.energy.gov/DocumentsandMedia/final_1839.pdf (undated webpage).

[19] DOE and FERC 2006.

### A.2.2 Description of the Metric and Measurable Elements

This section addresses 1) the extent of sharing of SCADA information from BAs upward to RCs and back to the BAs, and 2) the extent of institutionalized sharing of synchrophasor data among utilities, BAs, and RCs.

*(Metric 2.a) Total SCADA points shared per substation (ratio)*—the number of SCADA transmission grid measurement points from grid assets that are shared by BAs with RCs, plus the number of SCADA measurement points shared by the RCs with BAs, divided by the number of substations:

(Total_Points_BAs→RCs + Total_Points_RCs→BAs) / Total_Substations

- *Total_Points_BAs→RCs*: the number of transmission-grid measurement points (e.g., voltage, power flow, etc.) from grid assets routinely shared by a control area with the RC responsible for supervising its region. A larger number shows that a more complete picture of grid status is being shared with the RC. *Measurement point* corresponds to a sensor, not its time-series output; i.e., each sensor counts as "one" regardless of the frequency of the measurements it records or that are shared. The phrase "from grid assets" is intended to prevent duplicate counts of a single measurement point, to which adjoining BAs jointly have access and which they forward to the Reliability Coordinator.
- *Total_Points_RCs→BAs*: the number of transmission-grid measurement points routinely shared by the RC back to the BAs under its purview. The RC may share a set of data points with each of the BAs; each measurement point shared counts as "one" regardless of how many BAs receive it. Again, this is to prevent counting the measurement point once for each of many BAs that may receive it. This definition presumes that if a measurement point is shared with one BA, it would be available to all of them. By adding the measurement-point data shared in each direction, there is an implicit "perfect score" for a measurement point of exactly two, representing full two-way data sharing. If state estimates based on the data are shared by the RC, instead of raw data, then this should be counted as full two-way data flow.
- *Total_Substations:* The denominator of the metric is defined as the total number of electricity service provider substations within the BAs supervised by the RC. This is chosen instead of the number of busses used to model the system because it is less ambiguous.

Metric 2.a can be used at any level of the grid, but should be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

*(Metric 2.b) Fraction of transmission-level synchrophasor measurement points shared multilaterally (%)*—the fraction shared is the number of phasor measurement points routinely

shared via a multilateral institutional arrangement, divided by the total number installed in a region of the power grid:

Total_Phasor_Measurment_Points_Shared / Total_Phasor_Measurement_Points

- *Total_Phasor_Measurement_Points_Shared:* One count for each measurement from each transmission-level PMU or equivalent that is routinely shared via a multilateral institutional arrangement. This intentionally excludes bilateral arrangements because they are difficult to track, are less likely to persist over time, and may not be comprehensive.
- *Total_Phasor_Measurement_Points:* One count for each measurement from each PMU or equivalent installed on the grid at voltage levels above distribution voltage. Many new grid-sensing, control, and protection devices have PMU capabilities built in; if they are installed on the distribution system, they would not be counted.

Metric 2.b can be derived for any region of the grid, but will be computed and reported for each interconnection in the U.S. and for the U.S. grid as a whole.

### A.2.3 Deployment Trends and Projections

A recent survey by Newton-Evans Research[20] indicates there is significant sharing of measurement, analysis, and control data from electricity service provider control systems for transmission and distribution (SCADA, energy management systems [EMS], and distribution management systems [DMS]) with other grid entities, including regional control centers and other electricity operators. The survey was completed by over 100 utilities in the U.S. and Canada, representing a total of 66,129,387 end-use customers.[21] Utilities were asked to report the amount of EMS/SCADA/DMS systems in place, and specify the type of system. Results from the 2010 survey are represented in Figure A.4.

[20] Newton-Evans Research Company. 2010. *Market Trends Digest*. Newton-Evans Research Company, Endicott City, Maryland. Accessed November 29, 2010 at http://www.newton-evans.com/mtdigest/mtd3q10.pdf (undated webpage).
[21] Newton-Evans Research Company 2010.

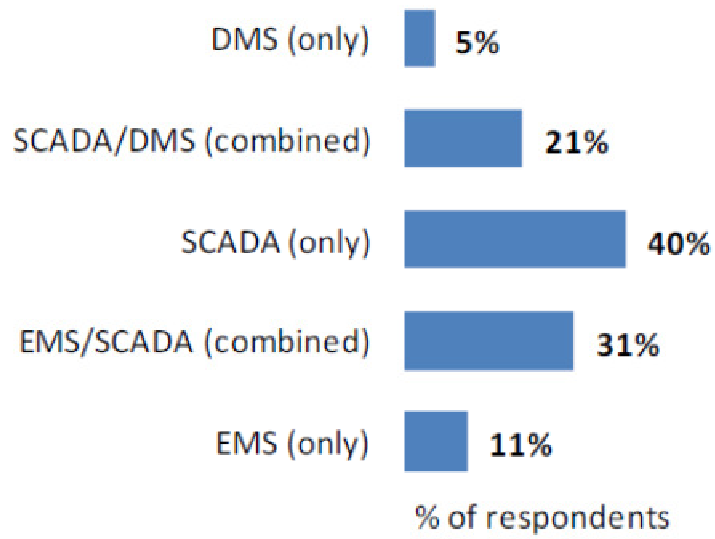


**Figure A.4**. Current Installations of EMS/SCADA/DMS Systems by Type[22]

The data for Metric 2.b was obtained from the participants of the North American SynchroPhasor Initiative (NASPI), a joint DOE-NERC effort to facilitate and expand the implementation of phasor technology for enhancing power system situational awareness and reliability. The results for Metric 2.b are shown in Table A.2. The table shows the total number of PMUs installed, the total number shared on a multilateral basis through institutions such as NASPI, and the fraction of transmission-level phasor-measurement points shared multilaterally (Metric 2.b) for each North American interconnection. Only the Eastern Interconnection currently has a multilateral data sharing agreement, which involves 86 percent of the 104 PMUs. For the entire North American transmission grid, 51 percent of the installed 175 PMU data points are shared.

**Table A.2**. Fraction of PMU Data Points Shared in the North American Transmission Grid

| Interconnection | PMUs Installed | PMUs with Multilateral Data Sharing Agreements | Fraction Shared Multilaterally |
|---|---|---|---|
| Electric Reliability Council of Texas | 0 | 0 | (NA) |
| Eastern Interconnection | 104 | 89 | 86% |
| Western Interconnection | 61 | 0 | 0% |
| Quebec Interconnection | 10 | 0 | 0% |
| Total, North American Transmission Grid | 175 | 89 | 51% |

[22] Newton-Evans 2010.

#### A.2.3.1 ARRA Funding to Dramatically Increase PMU Count

The most telling data on the implementation side of the smart grid is the number of ARRA-funded installations of networked phasor measurement units, which, as of April 13, 2010, was projected by DOE to be 877 units; this is six times the installed base of units.[23]

#### A.2.3.2 Distribution-Level SCADA Data Use and Sharing

The SCADA test bed evaluation report[24] found significant effort in the electricity service provider sector to improve security in substations. Utilities were constantly replacing electromechanical relays with digital relays and moving to the latest levels of automation. As substation automation is pursued, company standards are emphasizing cyber security, new standards and the current best practices. The study showed that standards have begun to address automation, with implementation to follow.

#### A.2.3.3 State-Level Influence on Real-Time Data Sharing:[25]

California's electricity grid management is a result of the ongoing transition from vertically integrated utilities serving native loads to an ISO managing competitive energy markets. Currently, the traditional approach to reliability management—construction of new transmission lines—has been delayed due to unresolved financing and recovery of transmission project costs. Without new investments in transmission infrastructure, managing reliability by system operators will be deprived of better real-time information, causing operating margins to drop. The Real-Time Grid Reliability Management project led to first-ever demonstrations of two prototype real-time software tools allowing voltage security assessment and phasor monitoring, along with a scoping study on improving load and generator response models.

#### A.2.3.4 Stakeholder Influences

Aspects of the U.S. electrical transmission system are regulated on both the federal level (reliability and interstate commerce) and at the state level (siting, prudency of investment, rate recovery). Input and planning for the transmission infrastructure are conducted, in increasing

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[23] Overholt P. 2010. "North American SynchroPhasor Initiative (NASPI) and DOE's Smart Grid Investment Grants." Presented at the EEI Transmission, Distribution and Metering Conference. April 11-14, 2010, Arlington, Virginia. Accessed October 8, 2010 at http://www.eei.org/meetings/Meeting%20Documents/2010-04-TDM-Tuesday-4-Overholt-Philip.pdf (undated webpage).

[24] INL – Idaho National Laboratory. 2009. *National SCADA Test Bed Substation Automation Evaluation Report*. INL/EXT-09-15321, Idaho National Laboratory, Idaho Falls, Idaho. Accessed October 21, 2010 at http://www.inl.gov/technicalpublications/Documents/4374057.pdf (undated webpage).

[25] Eto J, M Parashar, B Lesieutre, NJ Lewis, J Cole, and L Miller. 2008. *Real-Time Grid Reliability Management*. CEC-500-2008-049. Prepared by Lawrence Berkeley National Laboratory for the PIER Transmission Research Program, California Energy Commission, Sacramento, California. Accessed October 21, 2010 at http://certs.lbl.gov/pdf/cec-500-2008-049-report.pdf (undated webpage).

levels of detail and ultimate authority, by groups of state/regional governments, regional RCs, RTOs or ISOs (where they exist), and the utilities themselves. The planning and operation of the transmission grid involves the participation of a very large number of stakeholders, as well.

Among the stakeholders identified in Section 1.3 of this report, the following have special interest in transmission-level real-time data sharing (Metrics 2.a and 2.b):

- transmission providers and BAs – The metrics provide a benchmark for transmission providers and BAs sharing information that raises their situational awareness, can increase reliability, and may eventually result in wide-area control schemes that help realize the goal of a self-healing grid.
- reliability coordinators including NERC – The metrics provide a benchmark of progress toward increasing sharing of data by NERC's constituents. Data sharing helps NERC achieve its reliability goals. The existence of the metrics themselves could serve as motivation toward institutionalizing data-sharing mechanisms (especially for phasor data).
- products and service providers – Increased sharing of transmission data over wide areas opens up opportunities to develop new analysis applications driven by the data, which, in turn, may help promote sales and installation of phasor-measurement-capable devices.
- local, state, and federal energy policy makers; policy advocates – The existence of the metrics helps them focus on and drive the institutionalization of data-sharing mechanisms.

Other stakeholders with less direct interest include:

- generation and demand wholesale electricity traders/brokers – They benefit from the more reliable electric grid that sharing data enables, because market-based dispatch is less often disrupted by operational contingencies. As of September 7, 2010, electric grid data sharing was significantly increased due to the signing of a data sharing agreement in the WECC. Participants in the initiative, the Western Interconnection Synchrophasor Program (WISP), which include a large number of Western utilities, executed a data-sharing agreement as part of the North American Synchrophasor Initiative.[26]
- distribution-service providers – They benefit indirectly because the more-reliable bulk-power system that data sharing will enable causes less disruption to their distribution systems.
- electric-service retailers and end users – They benefit from being able to offer and obtain more reliable electric service.

[26] NERC – North American Electric Reliability Corporation. September 7, 2010b. "Data-Sharing Agreement Executed as Part of the North American Synchrophasor Initiative." Press Release. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed October 21, 2010 at www.nerc.com/fileUploads/File/newsletters/NERCNews-2010-09.pdf (last updated December 21, 2010).

### A.2.3.5 Regional Influences

The metrics are measured for each interconnection because of the strong regional differences associated with the size and governing institutions for each of the three U.S. interconnections. ERCOT is by far the smallest of the three in terms of population, number of substations, load served, and geographic area. It also has the most unified institutional arrangement, with ERCOT acting as the regional transmission operator and planner, the market operator, and the RC. As such, it has great authority to engage constituent utilities in integrating their transmission data.

The Western Interconnection is nearly as large in extent as the Eastern Interconnection, yet serves a significantly smaller population scattered mostly in widely separated pockets. It's widely separated population centers and generation cause it to have special problems with low-frequency oscillations and dynamic stability, issues that led to the 1996 blackouts and have driven it to be an early adopter of data sharing arrangements. The Western Interconnection (WECC[27]) was created in 2002 with a focus on wide-area issues associated with reliability. Of particular note with respect to Metric 2.b, members of the Western Interconnection were the early pioneers of phasor data collection and sharing in the 1990s.

WECC's West-Wide System Model concept that began in 2005 has come to fruition with the issue of a Request for Proposals for a Base Case Coordination System (BCCS)[28] in 2009. This project will be overseen by the WECC Regional Transmission Expansion Planning (RTEP) project, which is being supported with ARRA funds. In addition to the BCCS work, other projects include 10- and 20-year transmission plans for WECC expansion of transmission planning activities, such as creation of a Scenario Planning Group to facilitate stakeholder involvement.[29] This is an example of how data sharing enables increased levels of situational awareness that should result in higher reliability. This development will drive increased data sharing that should result in higher values for Metric 2a. As of April 10, 2010, the WECC reliability coordinator began

[27] WECC – Western Electricity Coordinating Council. 2010. *WECC Annual Review: January 2009 – July 2010*. Western Electricity Coordinating Council, Salt Lake City, Utah. Accessed October 26, 2010 at http://www.wecc.biz/library/WECC%20Documents/Publications/WECCAnnual.pdf (undated webpage).

[28] WECC – Western Electricity Coordinating Council. 2009. *Base Case Coordination System*. Western Electricity Coordinating Council, Salt Lake City, Utah. Accessed October 21, 2010 at http://www.wecc.biz/Planning/Reliability%20Planning/BCCS/default.aspx (undated webpage).

[29] Woertz B. 2010. *Scenario Planning Steering Group: What It is and Why It's Important*. Western Electricity Coordinating Council, Salt Lake City, Utah. Accessed October 21, 2010 at http://www.wecc.biz/committees/BOD/TEPPC/SPSG/SPSG%20Update%20for%20Transmission%20Owners,%20Operators%20and%20Developers/Lists/Agendas/1/Transmission%20Owners,%20Operators%20and%20Developers%2006-08-2010.pdf (last updated June 8, 2010).

requiring Bulk Electricity System (BES) operating information[30] to perform its functions, as defined by the NERC mandatory reliability standards.

The Eastern Interconnection with its large area, dense population, and closer proximity of population centers to generation, has 13 RCs compared to the Western Interconnection's three. The eastern grid is relatively "stiff" in that it does not exhibit the oscillatory behavior that the Western Interconnection does. The 1996 and 2003 blackouts clearly showed that such events can extend beyond even the larger areas of a single RC, yet the Eastern Interconnection does not have an interconnection-wide institution charged with reliability like the WECC that can help drive data sharing. NASPI's Planning and Implementation Task Force will develop and maintain a frequency response baseline for the Eastern Interconnection, as well as develop and maintain a baseline for inter-area power oscillations in the Eastern Interconnection.[31]

Partly as a result of the 2003 blackout, however, an Eastern Interconnection Phasor Pilot (EIPP) project was established that has pioneered phasor data sharing with the notion of phasor data concentrators that collect and archive all of it. The EIPP is the precursor of NASPI, which is attempting to formally institutionalize data sharing, among its other objectives.

## A.2.4 Challenges

### A.2.4.1 Technical Challenges

The principal technical challenges involved with data sharing at the transmission level involve the level of effort to identify, configure, and maintain the data to be exchanged between parties. Standard protocols exist for inter-control center site data exchange and phasor data exchange. Most suppliers of control center systems support these standards; however, complete, unambiguous interoperability requires significant processing and testing. Besides the data-exchange protocols, common naming conventions and unambiguous identity services would make integration and maintenance easier. Software interfaces that support publishing and interrogation services that are consistent with cyber security and information privacy policies (see Business and Financial Challenges, below) would reduce the manual labor necessary to support data sharing.

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[30] Perez L. April 10, 2010. *Compliance with Mandatory Reliability Standards – The Operating Data and Information Required by the WECC Reliability Coordinator (RC) and the Issuance of WECC RC Directives*, Rev 1. Western Electricity Coordinating Council, Salt Lake City, Utah. Accessed October 21, 2010 at http://www.wecc.biz/awareness/Reliability/Documents/Data%20Directives%20Letter%204-10-10.pdf (last updated April 10, 2010).

[31] NASPI PITT – North American Synchro-Phasor Initiative Planning and Implementation Team. 2010. *North American Synchro-Phasor Initiative Planning Implementation Task Force: Mid-Term Workplan*. Accessed October 21, 2010 at https://www.naspi.org/site/Module/Meeting/Reports/SubReports/pitt.aspx (last updated June 23, 2010).

Situational awareness and system operations applications, such as state estimation, also require the sharing of system modeling data. Power system models are complex and continually change as parts of the system are taken out of service temporarily, or new construction is added. Ownership and responsibility rights are also continually changing and require periodic updates; data sharing initiatives can be put on hold or discarded because the parties involved are not willing to support and exchange the requisite system models. Agreement on technical approaches and services can help reduce model maintenance and the burden of keeping neighbor models consistent; however, the problems are complex to explain, and, therefore, often underappreciated by the organizations involved.

#### A.2.4.2 Business and Financial Challenges

There are procedural, business, and privacy issues that hinder sharing of data and information collected by an electricity service provider with peers and higher-level grid RCs. Circumstances could require sharing of information with non-grid entities such as emergency-response centers or state and federal government agencies. Challenges to data sharing include:

- competitive intelligence – could be used in corporate takeovers, service-territory takeovers, change to municipal service by cities or electricity service provider districts, or competition to serve areas of growth that do not currently have service
- market intelligence – such as business actions that cause a change of service-territory market intelligence; market operators may be able to gather information to enhance their bidding strategies in wholesale markets, and regulated utilities want to limit this
- second guessing and prudency reviews – potential for legal action from regulators and competitors
- financial penalties – in the form of fines from regulators, lawsuits from customers, and reduced incentive payments from regulators
- data security – potential highlighting of physical or control-system vulnerabilities.

When ARRA funds were allocated, DOE identified a number of challenges, including those listed above, related to PMU data sharing. To mitigate these barriers, the Office of Electricity Delivery and Energy Reliability (OE) proposed that NERC develop a comprehensive non-disclosure agreement and phasor network communication specification to ensure safe and effective sharing of data.[32]

[32] OE – Office of Electricity Delivery and Energy Reliability. 2009. *Office of Electricity Delivery and Energy Reliability Recovery Program Plan*, pg. 15. Office of Electricity Delivery and Energy Reliability, Washington, D.C. Accessed October 21, 2010 at http://www.energy.gov/recovery/documents/Office_of_Electric_Delivery-Energy_Reliability_Recovery_Program_Plan.pdf (last updated June 3, 2009).

### A.2.5 Metric Recommendations

The research team was not able to access data to measure the deployment trends for Metric 2a. The intention of the 2009 Smart Grid System Report (SGSR) had been to gather this information from key industry stakeholders, such as the Data Exchange Working Group or the Reliability Coordinator Working Group, both under the NERC Operating Committee. A review of information from NERC's website on those groups identified no reference to information applicable to Metric 2a.

For Metrics 2a and 2b, it should be recognized that data exchange at the bulk grid/transmission level is only a means to an end. The end result is situational awareness leading to increased reliability and eventually a self-healing grid. Exchanging data does not accomplish anything, in and of itself. If metrics could be developed that better graphically represent the data being used, which applications it was being used for, and what the geographic/topological scales of the analyses are, these would better capture the intent of data sharing metrics for the transmission grid.

A more pragmatic approach to replacing Metric 2a would be to survey regional coordinators and/or balancing authorities about the visualization tools that their operators use to turn SCADA and PMU data into actionable information. The California ISO uses several tools of this nature. One such tool measures voltages and voltage reserves throughout the Western Interconnection. Diagnostic analysis is conducted to identify voltage irregularities and evaluate options to address them (Figure A.5).

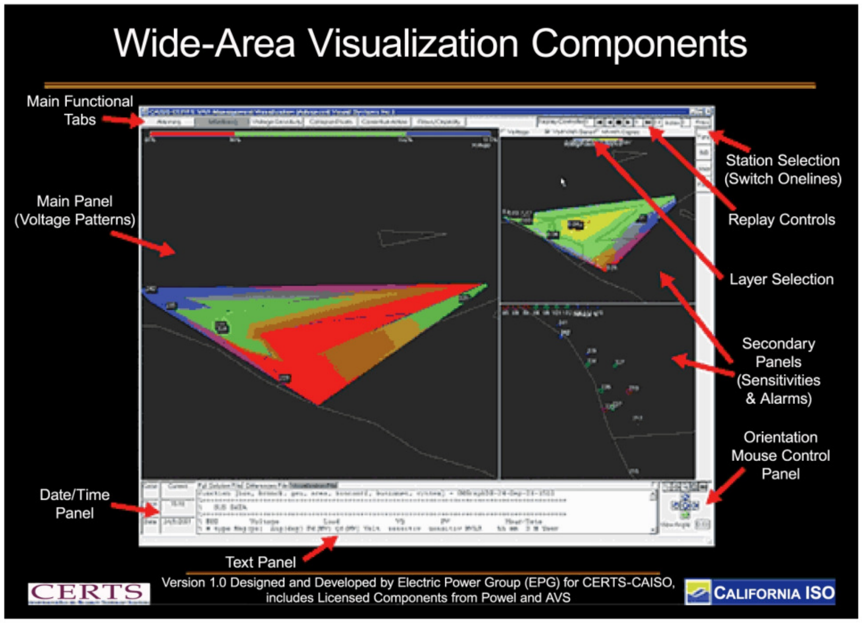


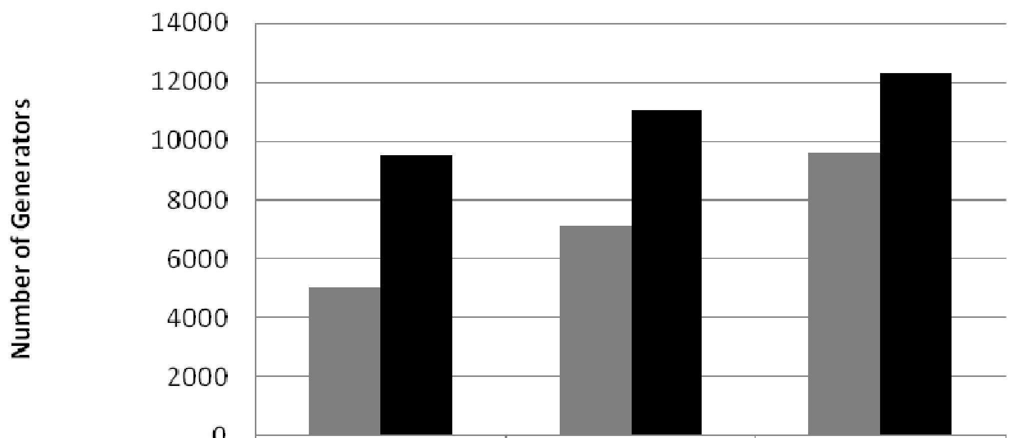

**Figure A.5**. Wide-Area Voltage Monitoring Display[33]

[33] CERTS – Consortium for Electric Reliability Technology Solutions. Undated. *CERTS VAR-Voltage Management Tool*. Consortium for Electric Reliability Technology Solutions. Accessed September 28, 2010 at http://certs.lbl.gov/certs-rtkey-var.html (undated webpage).

# A.3 Metric #3: Standard Distributed Resource Connection Policies

## A.3.1 Introduction and Background

The increasing presence of distributed energy resources (DER) among electricity service provider customers has led to various efforts for standardizing the process of interconnecting these resources to the grid. In 2008, the Energy Information Administration (EIA) reported that 9,591 electricity service providers or customer-owned distributed generators were grid-connected, representing a total capacity of 12,863 MW.[34] In addition, the EIA reported 12,262 dispersed generators (not grid-connected), representing 9,773 MW for owners/operators of a distribution system. Figure A.6 illustrates the growth of grid and non-grid-connected DER from 2006 to 2008. Benefits of distributed power generation such as peak-load reduction, combined heat and power (CHP) generation, base load power and improved power quality can be realized by both consumers and service providers. Providing interconnection standards for DER could allow some energy production to become decentralized and remotely monitored.




| | 2006 | 2007 | 2008 |
|---|---|---|---|
| ■ Distributed Gen. | 5044 | 7131 | 9591 |
| ■ Dispersed Gen. | 9536 | 11057 | 12262 |

**Figure A.6**. Distributed and Dispersed Generation Growth (2006 to 2008)

Interconnection standards have not been adopted in all states; cost, time lag, and onerous review processes associated with interconnecting DER to the grid are often cited as major

[34] EIA – Energy Information Administration. 2008. "File 6." Form EIA-861 Database. Energy Information Administration, Washington, D.C. Accessed July 23, 2010 at http://www.eia.doe.gov/pub/electricity/f86108.zip (undated).

barriers to further adoption. Federal legislation attempting to deal with this issue emerged in progressively stronger language, resulting in the Energy Policy Act of 2005 (EPACT 2005), which requires all state and non-state utilities to consider adopting interconnection standards based on the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547.[35] IEEE 1547, which was published in 2003, looks strictly at the technical aspects of DER interconnection, providing a standard that limits the negative impact of these resources on the grid.[36] Currently, IEEE is working on standard 1547.6 and 1547.8, which will expand interoperability and technical requirements surrounding DER interconnection to secondary networks.

In part to address some of the permitting aspects of interconnection, FERC issued FERC Order 2006, which mandated that all public utilities that own transmission assets provide a standard connection agreement for small generators (under 20 MW).[37] Additionally, the American Clean Energy and Security Act of 2009 (ACES 2009), which was introduced in the House, could increase adoption of interconnection standards by offering three federal renewable-energy credits for each megawatt-hour (MWh) of electricity produced by a DER facility.[38]

To expand favorability of interconnection standards, the Energy Independence and Security Act of 2007 (EISA) requires interoperability policies to accommodate consumer distributed resources, including distributed generation, renewable generation, energy storage, energy efficiency, and demand response.[39] To meet this requirement, the NIST released the *NIST Framework and Roadmap for Smart Grid Interoperability Standards*, early in 2010. One of the sixteen priority areas within the standards framework is recognition of distribution grid management from centralized and decentralized power sources.[40]

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[35] 42 USC 15801 et seq. 1986. 2005. *Energy Policy Act of 2005*. Public Law 109-58, as amended. Accessed November 26, 2008 at http://www.oe.energy.gov/DocumentsandMedia/EPACT05ConferenceReport0.pdf (undated webpage).

[36] Cook C and R Haynes. 2006. *Analysis of U.S. Interconnection and Net-Metering Policy*. North Carolina Solar Center, North Carolina State University, Raleigh, North Carolina. Accessed October 18, 2010 at http://www.dsireusa.org/documents/PolicyPublications/ASES2006_Haynes_Cook.pdf (undated webpage).

[37] 18 CFR 35. 2005. "Standardization of Small Generator Interconnection Agreements and Procedures; Order on Rehearing." *Code of Federal Regulations*, Federal Energy Regulatory Commission. Accessed November 24, 2008 at http://www.gpo.gov/fdsys/pkg/FR-2005-11-30/pdf/05-23461.pdf (undated webpage).

[38] H.R. 2454. 2009. *American Clean Energy and Security Act of 2009*. Accessed July 15, 2010 at http://www.govtrack.us/congress/bill.xpd?bill=h111-2454 (undated webpage).

[39] 110 USC Sec. 1305. 2007. *Energy Independence and Security Act of 2007 (EISA)*. Public Law 110-140. Accessed July 16, 2010 at http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h6enr.txt.pdf (undated webpage).

[40] NIST – National Institute of Standards and Technology. 2010. *NIST Framework and Roadmap for Smart Grid Interoperability.* NIST Special Publication 1108, National Institute of Standards and Technology, Gaithersburg, Maryland. Accessed July 16, 2010 at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf (undated webpage).

### A.3.2 Description of Metric and Measurable Elements

(Metric 3) The percentage of utilities with standard distributed resource interconnection policies.

The topic also discusses the commonality of such policies across utilities.

### A.3.3 Deployment Trends and Projections

As of June 2010, 39 states, Washington, D.C., and Puerto Rico have adopted variations of interconnection policy. Distributed resource interconnection policies have been either implemented or expanded in 14 states since 2008, thus promoting the advancement of distributed generation technologies. By categorizing states based on their interconnection policies and identifying the number of utilities in each state, the research team was able to estimate the percentage of utilities with standard resource interconnection policies. Based on this approach, it is estimated that roughly 83.9 percent of utilities currently have a standard resource interconnection policy in place, compared to 61 percent in 2008.[41]

As illustrated in Figure A.7, nine states plus Puerto Rico have no limits on the size of system allowed within their programs, 18 states limit generator interconnection based on energy type or kilowatt (kW) capacity, and 13 states limit their standards to net-metering systems only. Many states that have taken aggressive action on distributed generation have done so to incorporate grid-connected renewable energy to meet renewable portfolio standards or energy efficiency requirements.

[41] EIA – Energy Information Administration. 2002. *Contact Information for Electric Utilities by State*. Energy Information Administration, Washington, D.C. Accessed November 24, 2008 at http://www.eia.doe.gov/cneaf/electricity/utility/utiltabs.html (last updated October 8, 2010).

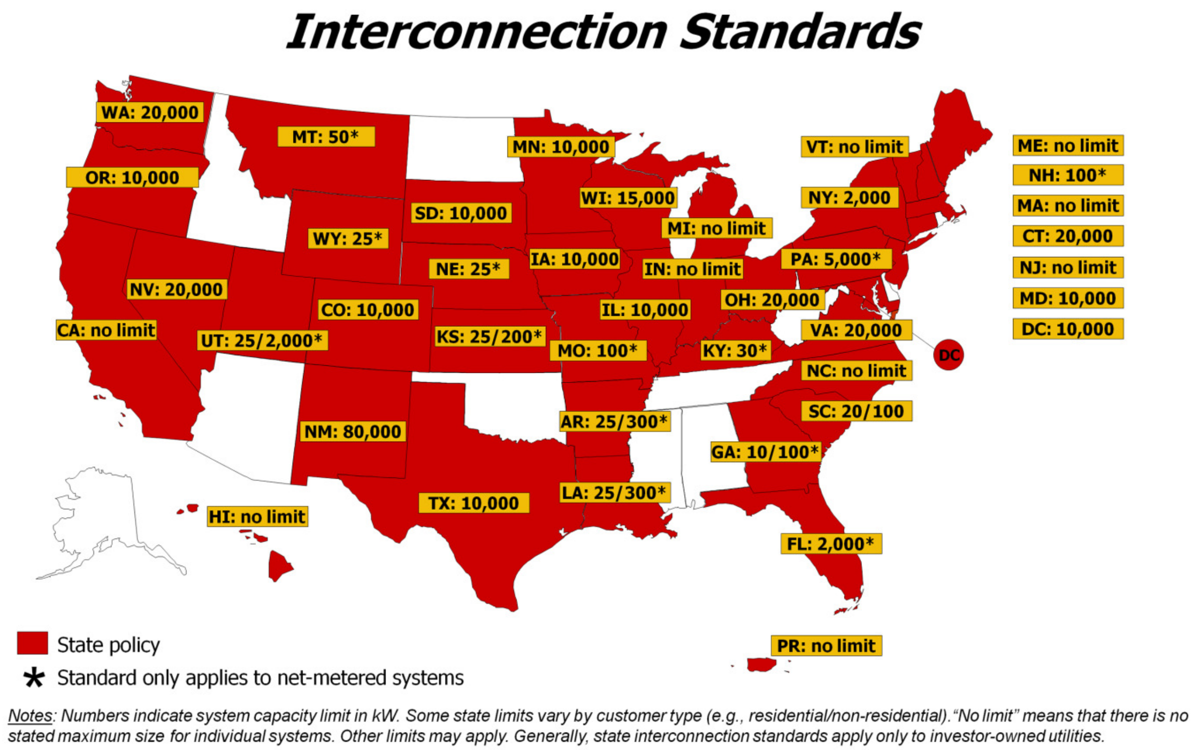


**Figure A.7**. State Interconnection Standards[42]

In order for interconnection standards to be accepted by end users, states must draft them in a manner that encourages consumer participation. In 2009, the Interstate Renewable Energy Council (IREC) and the Network for New Energy Choices (NNEC) analyzed the favorability of state interconnection standards based on a 14-point numerical grading system that awarded points for active promotion and deducted points for discouraging DER advancement. The 2009 SGSR used research from the Environmental Protection Agency's (EPA) clean energy programs, which based their favorability standards on six factors that affect interconnection policy. This study was used to evaluate the favorability of interconnection standards in the 2009 SGSR. Table A.3 illustrates the differences between the IREC/NNEC study cited in this 2011 SGSR and the EPA favorability scoring categories cited in the 2009 SGSR.

[42] DSIRE – Database of State Incentives for Renewable Energy. 2010. *Interconnection Standards*. Accessed July 15, 2010 at http://www.dsireusa.org/documents/summarymaps/interconnection.ppt (undated webpage).

**Table A.3**. Favorability Scoring Categories

| IREC & NNEC Policy Grading Categories | Factors Affecting DG-Friendliness of Interconnection Standards Used by EPA |
|---|---|
| Standard Form Agreement | Standard Interconnection Forms |
| Timelines | Timelines |
| Individual System Capacity | System Size Limits |
| Insurance Requirements | Insurance Requirements |
| Eligible Technologies | Technical Requirements |
| Engineering Charges | Simplified Procedure for Small Systems (≤ 10 MW) |
| External Disconnect Switch | |
| Certification | |
| Technical Screens | |
| Network Interconnection | |
| Interconnection Charges | |
| "Breakpoints" for Interconnection Process | |
| Dispute Resolution | |
| Rule Coverage | |

Unlike the grading criteria in the EPA study, which measured six policy issues, the grading system designed by IREC and NNEC (Table A.3) numerically evaluated 14 policy issues specific to interconnection, including technological considerations, system capacity, cost-effectiveness, insurance requirements, and timelines.[43] The A through F grading system, presented in Figure A.8, was established on the basis of the categories listed in Table A.3 and reflect an assessment of each state's policies based on these criteria. Figure A.8 is a representation of the favorability of interconnection standards in each state based on IREC and NNEC criteria.

[43] NNEC – Network for New Energy Choices. 2009. *Freeing the Grid: Best and Worst Practices in State Net Metering Policies and Interconnection Procedures.* Network for New Energy Choices, New York. Accessed July 15, 2010 at http://www.newenergychoices.org/uploads/FreeingTheGrid2009.pdf (undated webpage).

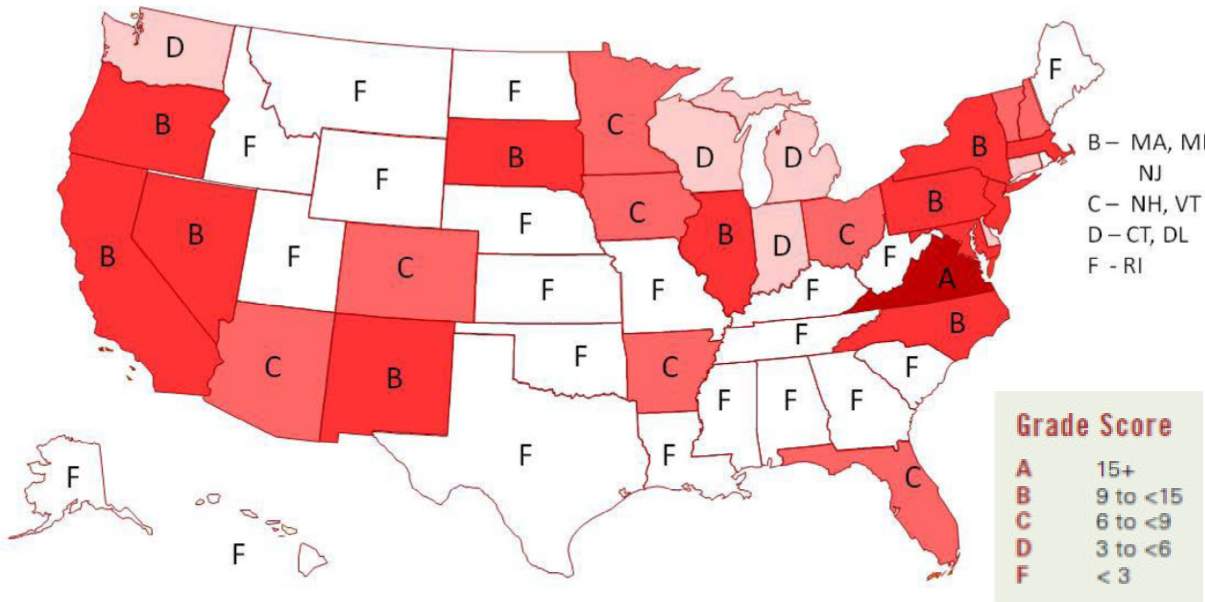


**Figure A.8**. Favorability of State Interconnection Standards for Grid Connection[44]

Based on interconnection standards measured by IREC and NNEC, findings of the study indicate that 13 states have policies favorable to grid interconnection, 15 states have neutral policies, and 22 states (including those with no standard) have unfavorable policies. Results from the 2009 study are similar to those of the EPA study, which determined that out of all states with interconnection standards enacted, 15 states had favorable policies, 12 states had neutral policies, and 5 states had unfavorable policies.[45]

#### A.3.3.1 Associated Stakeholders

Interconnection policy stakeholders include

- distribution-service providers and utilities, who will ultimately be responsible for managing the grid impact of these resources
- manufactures of DER products and services, who would benefit significantly from easier interconnection standards
- regulators and policy makers, who are concerned with how electricity service providers choose to account for the costs of these resources, as well as other related legislation, such as meeting renewable-portfolio-standard requirements
- end users who have distributed resources on their properties and want to tap into the potential benefits of selling power back to the grid

[44]NNEC 2009.
[45] EPA – U.S. Environmental Protection Agency. 2008. *Interconnection Standards*. Combined Heat and Power Partnership (CHP), U.S. Environmental Protection Agency, Washington, D.C. Accessed August 6, 2010 at http://www.epa.gov/chp/state-policy/interconnection.html (last updated October 7, 2010).

- environmental organizations and other advocacy groups who promote renewable DER technologies to decrease greenhouse gas emissions or to promote energy independence.

#### A.3.3.2 Regional Influences

Regional differences in perception of the costs and benefits associated with distributed resources have influenced where they are deployed. Many of the regional policies that have emerged are driven by state legislation designed to cap overall emissions, to balance load, or for security purposes. Below are specific examples of regional DER interconnection policy influences:

- In contrast with many states, California has had a DER incentive program since 2001. The Self-Generation Incentive Program has installed over 1,300 dispersed generators, representing approximately 400 MW of capacity, throughout the state.[46] In addition, the California Public Utilities Commission has created a renewable distributed energy collaborative to discuss challenges and goals for future DER promotion.
- In 2009, the State Corporation Commission of Virginia updated their Electric Utility Regulation Act to adopt interconnection standards for distributed generation systems smaller than 20 MW.[47] These standards were created to allow customers to efficiently connect renewable energy sources to the grid, limiting wait time and cost.
- New York, which was one of the first states to adopt a standard interconnection policy in 1999, has continued to provide support for distributed generation. In 2010, the state streamlined the application process for systems 25 kW or less, allowing a simplified process for DER grid interconnection.[48]
- Many states in the Southeast region have been resistant to implementing favorable standards for interconnection (see Figure A.8). Factors slowing penetration are similar to those associated with many energy efficiency standards, including historically low electricity

[46] Itron Inc. 2010. *Impacts of Distributed Generation: Final Report*. Prepared by Itron, Inc. for the California Public Utilities Commission, Energy Division Staff. Accessed July 16, 2010 at http://www.cpuc.ca.gov/NR/rdonlyres/750FD78D-9E2B-4837-A81A-6146A994CD62/0/ImpactsofDistributedGenerationReport_2010.pdf (undated webpage).

[47] Commonwealth of Virginia State Corporation Commission. 2009. *Status Report: Implementation of the Virginia Electric Utility Regulation Act*. Pursuant to 56-596 B of the Code of Virginia. Accessed July 16, 2010 at http://www.scc.virginia.gov/comm/reports/2009_veur.pdf (undated webpage).

[48] New York State Public Service Commission. 2010. *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems.* Revised July 15, 2010. Accessed July 16, 2010 at http://www.dps.state.ny.us/Modified_SIR-July2010-Final.pdf (undated webpage).

rates, close proximity to the nation's fossil fuel production, and high energy-demand lifestyles (energy consumption in the South is 43 percent of the U.S. total).[49]

## A.3.4 Challenges to Deployment

Barriers to DER interconnection may begin to diminish as more states adopt progressive policies to allow higher penetration of DER. Barriers will remain in certain regions such as the Southeast, where adoption of interconnection standards has been slow.

### A.3.4.1 Technical Challenges

There is still disagreement among some utilities and DER manufacturers about how to handle DER interconnection at high levels of penetration. With low levels of penetration, most utilities consider their distribution systems to be robust enough to handle disturbances in the system and unexpected DER disconnects. As the number of grid-connected DER systems grows, the back-feed of power to the grid could be significant enough to disrupt traditional transmission. Moreover, in order to employ the full potential of DER, states may need to expand their existing laws or institute new ones that allow flow of surplus energy back to the grid.[50]

In addition, with more renewable sources of energy such as wind, solar panels and other photovoltaic generators beginning to be connected to the grid, utilities face intermittency issues due to inconsistency of these energy types. Further, if climate legislation is passed, it may prove to be a barrier to more traditional forms of DER, such as diesel reciprocating engines.

### A.3.4.2 Business and Financial Challenges

Service providers still have difficulty making the business case for integration of distributed resources, especially without integrated distribution and transmission planning. While using DER can help providers reduce transmission congestion, these effects are difficult to model and are generally not within the purview of electricity service provider operations.

Business and financial challenges are also present on the demand side of the grid. Many state policies could provide enhanced financial incentives to consumers to promote DER installation. Productive interconnection standards could include renewable-energy tax credits,

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[49] Brown M, E Gumerman, X Sun, Y Baek, J Wang, R Cortes, and D Soumonni. 2010. *Energy Efficiency in the South.* Southeast Energy Efficiency Alliance, Atlanta, Georgia. Accessed September 14, 2010 at http://www.seealliance.org/se_efficiency_study/full_report_efficiency_in_the_south.pdf (undated webpage).

[50] Kaplan S. 2009. *Electric Power Transmission: Background and Policy Issues.* Congressional Research Service for U.S. Congress, Washington, D.C. Accessed July 15, 2010 at http://assets.opencrs.com/rpts/R40511_20090414.pdf (undated webpage).

public research and development (R&D) funding and removal of regulatory burdens such as those associated with unfavorability of interconnection standards.

### A.3.5 Metric Recommendations

Future smart grid metric reports should give consideration to both defining what constitutes a standard DER interconnection policy and identifying surveys, reports, or other literature that will yield consistent results over a longer time horizon. Also, consideration should be given to assessing the fairness of DER interconnection policies to encourage a level playing field for DER integrators, utilities, and ratepayers. Further, questions should be devised and used during the process of conducting interviews in support of future smart grid metric reports.

In addition, future reports should consider islanding and microgrids, which are beginning to represent a larger portion of distributed generation. Finally, the metric does not currently differentiate between non-renewable and renewable DER, which is a priority for many state energy efficiency policies.

# A.4 Metric #4: Regulatory Recovery for Smart Grid Investments

## A.4.1 Introduction and Background

Section 1252 of the Energy Policy Act of 2005 (EPACT 2005) outlines policies and objectives for encouraging a smart grid initiative, including the provision of time-based rates to customers and the ability to send and receive real-time price signals. While EPACT outlined objectives for advancing smart grid concepts, it did not require electricity service provider investment in smart grid technologies, nor did it establish or outline a regulatory framework to encourage such investment.

EISA did provide incentives for operators to undertake smart grid investments. Section 1306 authorized the Secretary of the DOE to establish the Smart Grid Investment Grant (SGIG) Program, which was designed to provide reimbursement for up to 20 percent of a company's investment in smart grid technologies. Section 1306 also outlined what constituted qualified investments and defined a process for applying for reimbursement. Section 1307 encouraged states to require service operators to demonstrate consideration for smart grid investments prior to investing in non-advanced grid technologies. Section 1307 also encouraged states to consider regulatory requirements that included the reimbursement of the book-value costs for any equipment rendered obsolete through smart grid investment.

In 2009, ARRA Designated $4.5 billion for electric grid modernization programs, including $3.4 billion for the SGIG program.[51] The program has awarded grants to 100 private companies, service providers, manufacturers, and cities, with total public-private investment amounting to over $8 billion.[52] Additionally, an interim rate procedure has been adopted by FERC, allowing utilities to submit rate filings, including single-issue rate filings to recover smart grid investment costs.[53] The interim policy will be active until interoperability standards proposed by NIST are finalized and instituted by the commission.

To date, many states have implemented or are considering renewable energy and energy efficiency standards that include smart grid technologies. Smart grid investments often are

[51] 111 USC Sec. 405. 2009. *The American Recovery and Reinvestment Act of 2009.* Public Law 111-5. Accessed July 22, 2010 at http://fdsys.gpo.gov/fdsys/pkg/BILLS-111hr1ENR/pdf/BILLS-111hr1ENR.pdf (undated webpage).

[52] DOE – U.S. Department of Energy. October 27, 2009a. "President Obama Announces $3.4 Billion Investment to Spur Transition to Smart Energy Grid." U.S. Department of Energy, Washington, D.C. Accessed June 14, 2010 at http://www.energy.gov/news2009/8216.htm (last updated October 27, 2009).

[53] 18 CFR Chapter I. 2009. "Smart Grid Policy." *Code of Federal Regulations*. Federal Energy Regulatory Commission. Accessed October 21, 2010 at http://www.ferc.gov/whats-new/comm-meet/2009/031909/E-22.pdf (undated webpage).

capital intensive, and include multiple jurisdictions within a provider's service area. While smart grid investments can achieve numerous operational efficiencies (e.g., reduce meter-reading costs, require fewer field visits, enhance billing accuracy, improve cash flow, improve information regarding outages, enhance response to outages), overall benefits and costs are still uncertain.[54] There is still debate among consumer and electricity service provider representatives whether smart grid benefits outweigh the costs.

A recent study of AMI estimated the costs of nationwide deployment of AMI technologies alone to be $40 billion.[55] Considering the significant expense, service providers must be sure that regulatory recovery is feasible; while the up-front costs of the investment are easy to calculate, the back-end benefits can be difficult to monetize within current regulatory valuation models.

### A.4.2 Description of Metric and Measurable Elements

(Metric 4) the weighted average (respondents' input weighted based on total customer share) percentage of smart grid investment recovered through rates.

### A.4.3 Deployment Trends and Projections

The smart grid interviews conducted for the 2011 report included 24 companies. Respondents were asked the following question: "What type of regulatory policies (beneficial regulatory treatment for investments made and risk taken) are in place to support smart-grid investment by your electricity service provider?" Of those interviewed,

- Thirteen companies (54.2 percent) indicated that there were no regulatory policies in place to support smart grid investment.
- Three companies (12.5 percent) indicated there were mandates in place to support investment in smart grid features, such as smart meters.
- Six companies (25 percent) indicated there were incentives in place to encourage smart grid investment.
- Eight companies (33.3 percent) indicated that there was some form of regulatory recovery for their smart grid investments.

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[54] Kaplan S. 2009. *Electric Power Transmission: Background and Policy Issues.* Congressional Research Service for U.S. Congress, Washington, D.C. Accessed July 18, 2010 at http://assets.opencrs.com/rpts/R40511_20090414.pdf (undated webpage).

[55] Faruqui A and S Sergici. 2009. *Household Response to Dynamic Pricing of Electricity—A Survey of the Experimental Evidence.* Accessed July 18, 2010 at http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf (undated webpage).

Companies were also asked to estimate the percentage of smart grid investments to date that has been recovered through rate recovery, and compare that total against their expectations for future investments in the smart grid. The service providers interviewed for the 2011 SGSR indicated that, on average (weighted), they are recovering 23.5 percent of their investment through rate structures, compared to 8.1 percent estimated for the 2009 SGSR, but predict regulatory recovery rates will expand in the future, ultimately reaching 37.3 percent. While state regulations for cost recovery of AMI and smart grid investments are still emerging, rate adjustments can be concentrated around decoupling, which is an adjustment mechanism that ensures an electricity service provider will recover the fixed costs approved by their regulatory commission, including an approved return on investment, regardless of sales volume. Types of decoupling include

- full decoupling – An electricity service provider recovers the allowed revenue, no matter the reason, for the difference in projected versus actual sales.
- partial decoupling – An electricity service provider recovers some of the difference between the allowed and actual revenue.
- limited decoupling – An electricity service provider recovers a true-up cost only when actual revenue deviates from allowed revenue for a specific reason.[56]

Other forms of regulatory recovery for smart grid investments include Lost Revenue Adjustment Mechanisms (LRAM)—riders and trackers that impose rate adjustments based on estimates of lost revenue from energy efficiency or supply-side management programs. When states decouple and/or impose LRAMs, the link between sales and revenue weakens, allowing utilities to recover fixed costs even though electricity demand may be decreasing because of energy efficiency programs.

As shown in Figure A.9, 13 states including the District of Columbia currently have a revenue decoupling mechanism in place, 8 states have pending policies, and 9 states have LRAMs, including Utah, which has a standard pending. Decoupling policies enacted since 2008 include Hawaii, Idaho, Massachusetts, Nevada, Oregon, Vermont, and Wisconsin.[57]

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[56] NREL – National Renewable Energy Laboratory. 2009. *Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities.* National Renewable Energy Laboratory, Golden, Colorado. Accessed July 20, 2010 at http://www.nrel.gov/docs/fy10osti/46606.pdf (undated webpage).

[57] IEE – Institute for Electric Efficiency. 2010a. *State Energy Efficiency Regulatory Frameworks*. Institute for Electric Efficiency, Washington, D.C. Accessed October 11, 2010 at http://www.edisonfoundation.net/IEE/issueBriefs/IEE_StateRegulatoryFrame_0710.pdf (undated webpage).

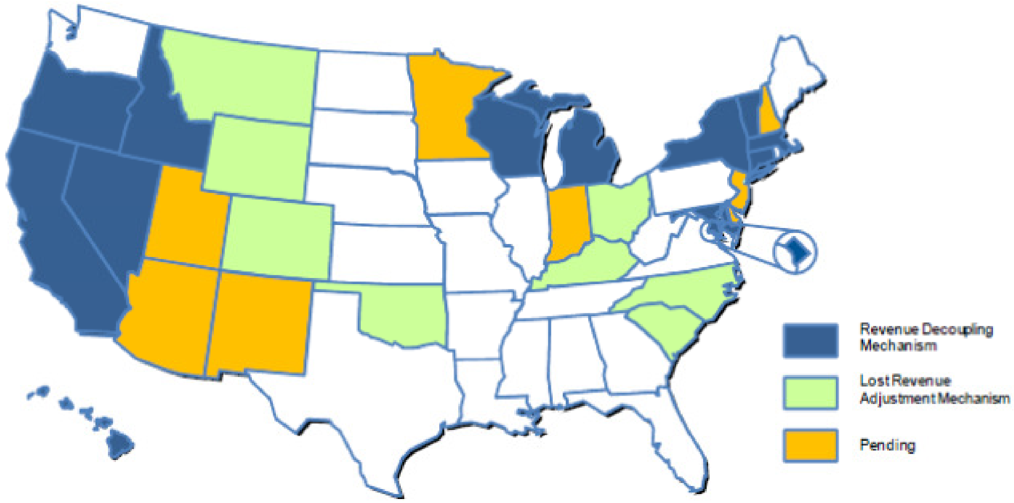


**Figure A.9**. Status of States with Decoupling or Lost Revenue Adjustment Mechanisms[58]

In addition to lost-margin recovery, increased use of state energy savings goals, such as renewable energy efficiency portfolio standards, have also influenced state regulatory commissions to expand financial incentives to electricity service providers that invest in energy saving mechanisms, such as energy efficiency programs that may leverage smart grid technologies. Figure A.10 presents states that have performance incentives for investor-owned utilities. Performance incentives are policies that promote energy reduction programs by awarding service providers and shareholders when a specified target level of energy efficiency is reached, thus promoting statewide energy efficiency programs and smart grid technology deployment. Decoupling and incentive program policies have impacted energy efficiency programs. As a result, such budgets have increased from $2.7 billion in 2007, to $3.2 billion in 2008, and $4.4 billion in 2009.[59]

[58] IEE 2010a.

[59] IEE – Institute for Electric Efficiency. 2010b. *Changes in State Regulatory Frameworks for Utility Administered Energy Efficiency Programs*. Institute for Electric Efficiency, Washington, D.C. Accessed October 11, 2010 at http://www.edisonfoundation.net/iee/issueBriefs/IEE_RegulatoryChanges2007-2010.pdf (undated webpage).

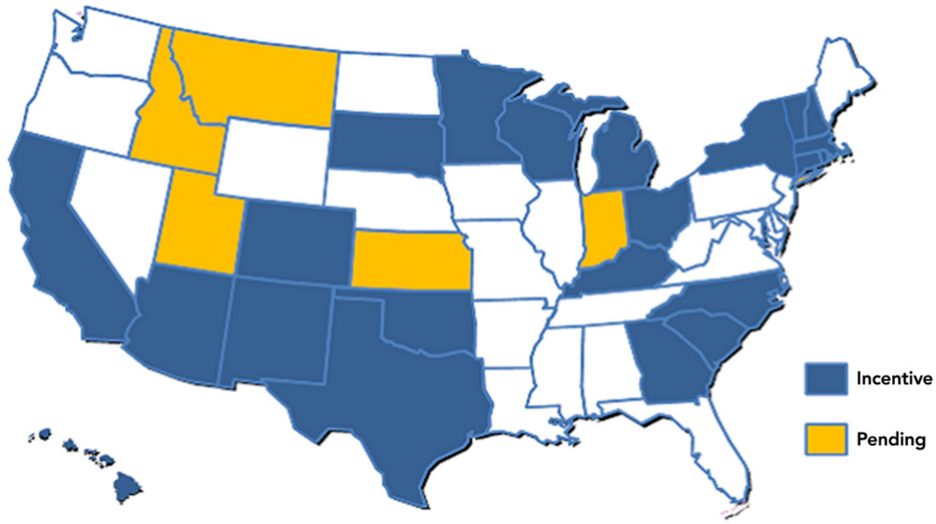


**Figure A.10**. Improved Performance Incentive Programs[60]

#### A.4.3.1 Associated Stakeholders

There are a number of stakeholders with an interest in regulatory recovery for smart grid investments:

- regulatory agencies considering smart grid business cases
- residential, commercial, and industrial customers who could benefit from the deployment of smart grid technologies
- transmission and distribution service providers and balancing authorities interested in reducing peak demand, enhancing efficiency, and reducing the costs to supply energy
- policy advocates, such as environmental organizations, interested in reducing the need for new power-generation plants; or, consumer advocacy groups monitoring end-user electricity service provider pricing tariffs
- policymakers interested in fostering competitive markets and managing load while reducing the need to expand existing generation, transmission, and distribution infrastructure.

#### A.4.3.2 Regional Influences

Traditionally, utilities seeking regulatory recovery for investments, including decoupling proposals, must do so by submitting a request to the state public utility commission (PUC) for review. Examples of states that have recently submitted such requests include:

[60] IEE 2010a.

- On July 1, 2010, Georgia Power submitted a request to the Georgia Public Service Commission (PSC) requesting an 8.2 percent, or $615 million, rate increase to recover capital costs of deploying smart grid technology and clean generation.[61] If approved, the rate increase will take place in 2011.
- In 2009, the Illinois Commerce Commission approved a rate increase of approximately $69 million for a Commonwealth Edison AMI pilot program.[62]
- In 2009, the Oklahoma Corporation Commission approved a request by Oklahoma Gas and Electric to provide a tariff rider to recover up to $20 million for the SmartPower program in Norman, Oklahoma.[63]
- The Hawaii PUC approved decoupling policies for all utilities in 2010.[64] By decoupling, the Hawaii PUC plans to spur electricity service provider investment in smart grid technologies as one way to meet renewable energy portfolio standards, which mandate a 25 percent decrease in energy consumption by 2020.
- In 2009, FERC approved a PG&E petition to recover $25 million for a synchrophasor project in California.[65] The project is the first to be approved using the interim smart grid cost recovery program enacted by FERC in 2009.

While decoupling, LRAM, and incentive programs have proved to be important factors for regulatory recovery of smart grid investments, there have been some programs that failed to gain stakeholder support. For example, in 2010, the Connecticut Department of Public Utility Control allowed proposed rate adjustments by Connecticut Light and Power (CL&P), but denied a request by the company to fully decouple sales from revenue.[66] Similarly, in May 2010, the Public Service Commission of Maryland rejected regulatory recovery for an $835 million

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[61] Georgia Power. July 1, 2010. "Georgia Power Seeks Cost Recovery of Investments in Cleaner Generation, Smart Grid, and Environmental Controls." Press Release. Georgia Power, Atlanta, Georgia. Accessed August 6, 2010 at http://www.smartgridnews.com/artman/uploads/1/Georgia_Power_Seeks_Cost_Recovery_of_Investments_in_Cleaner_Generation.pdf (last updated July 1, 2010).

[62] EEI – Edison Electric Institute. 2009. *State Regulatory Update: Smart Grid Cost Recovery*. Edison Electric Institute, Washington, D.C. Accessed August 6, 2010 at http://www.edisonfoundation.net/iee/reports/IEE_State_Update_SG_Cost_Recov.pdf (undated webpage).

[63] EEI 2009.

[64] IREC – Interstate Renewable Energy Council. March 1, 2010. "Hawaii PUC Approves Method of Electric Rate Decoupling." Accessed August 9, 2010 at http://irecusa.org/2010/03/hawaii-puc-approves-method-of-electric-rate-decoupling/ (undated webpage).

[65] FERC – Federal Energy Regulatory Commission. December 17, 2009. "FERC Approves First Smart Grid Proposal Using New Policy." Press Release, Docket No EL09-72-000. Accessed August 10, 2010 at http://www.ferc.gov/media/news-releases/2009/2009-4/12-17-09-E-4.asp (last updated June 28, 2010).

[66] DelGobbo KM, A Vazquez Bzdyra, and AJ Palermino. June 30, 2010. *Application of the Connecticut Light and Power Company to Amend its Rate Schedules (Final Decision)*. Docket No. 09-12-05, State of Connecticut Department of Public Utility Control, New Britain, Connecticut. Accessed August 11, 2010 at http://www.dpuc.state.ct.us/DOCKCURR.NSF/4c22436eef058861852573ee005bfa9d/10de737fccd5dad5852577520056612d/$FILE/091205-063010.doc (undated webpage).

proposal by Baltimore Gas and Electric (BGE) to install AMI meters at all customer homes and institute time-of-use pricing tariffs.[67]

## A.4.4 Challenges to Deployment

A number of technical and business/financial barriers are realized due to a lack of regulatory recovery of smart grid investments as outlined below.

### A.4.4.1 Technical Challenges

Technical barriers include:

- When making the case to electricity service provider commissions, technical barriers may exist due to the unproven nature of some smart grid technologies. Commissions may need assurance that specific equipment such as meters will not be obsolete in a few years as smart grid technology advances.
- Smart grid related projects vary by electric service provider in terms of functionality, requirements, and implementation approaches. General agreement is needed on the points in these systems where interfaces can be defined and stabilized. Such standards are being composed by NIST, but are still in development stages. (See Metric 19, Open Architecture/ Standards.)

### A.4.4.2 Business and Financial Challenges

Business and financial barriers include the following:

- There are significant costs to service providers when deploying new smart grid technologies. Regulatory recovery of these costs can be difficult to justify, which creates a disincentive to technology deployment.
- It may be difficult to demonstrate positive net benefits, causing consumer representatives to oppose deployment. Further, societal and environmental benefits are not currently quantified and included in the business case for smart grid investment.[68]

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[67] Nazarian DRM, HD Williams, S Brogan, L Brenner, and TM Goldsmith. June 21, 2010. *Order No. 83410: In the Matter of the Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for the Recovery of Cost*. Case No. 9208, Public Service Commission of Maryland. Accessed August 9, 2010 at http://webapp.psc.state.md.us/Intranet/sitesearch/whats_new/Order%2083410_BGE%20AMI%20Application_CN%209208.pdf (undated webpage).

[68] Miller J. 2010. *Understanding the Smart Grid Value Proposition*. Presented at the MACRUC 15th Annual Education Conference. June 28-29, 2010, Hershey, Pennsylvania. Accessed July 21, 2010 at http://www.narucmeetings.org/Presentations/Joe%20Miller_Understanding%20the%20benefits%20of%20smart%20grid.pdf (undated webpage).

- Due to the up-front costs involved, many service providers seek cost recovery for pilot programs or before smart grid technologies are deployed. Electricity service provider commissions may be hesitant to authorize rate increases for such programs.
- For operators providing service in multiple jurisdictions, the regulatory requirements in one area may not be consistent with those in another.
- Until the value proposition can be demonstrated to retail customers, the responsiveness of end users will be limited and thus limit the cost recovery potential of both aggregators and service providers. That is, consumers need to experience cost savings in order to support smart grid deployment. If smart grid devices cost more than the offsetting value of reduced energy consumption or if the savings are not well defined or understood, consumers may be unwilling to invest in them. Without an expectation of buy-in from consumers, innovators and service providers may also be reluctant to invest in smart grid technologies.

### A.4.5 Metric Recommendations

More information regarding percentage of decoupling or LRAM programs is desired. Information regarding specific electricity service provider participation in capital recovery programs was not found and should be included in future reports.

Education programs need to be developed that indicate the costs and benefits of smart grid programs and the associated laws and regulations that need to be developed to provide for the associated recovery of smart grid investments.

# A.5 Metric #5: Load Participation

## A.5.1 Introduction and Background

This metric measures the fraction of load served by interruptible tariffs, direct load control, and consumer load control. These properties are critical for enabling measurement and modeling of a smart grid's load participation and how it responds as an actual system.

"Demand response" is defined according to the DOE in its September 2007 report to Congress as follows:

*Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.*[69]

Demand response is typically viewed from a SCADA point of view as a form of additional capacity and is discussed in terms of MW. Demand response programs have seen quite a variation of interest over the years. The EIA reports that Demand Side Management (DSM) spending, one of the earlier forms of demand response (albeit focused primarily on energy efficiency measures with associated peak-load benefits) peaked at $2.74 billion in 1994 before declining to $1.3 billion in 2003,[70] and then rose to $3.7 billion in 2008 (nominal dollars).[71]

Figure A.11 graphs historic and projected levels of electricity sales by sectors. Notice that, historically, residential and commercial energy sales have been below or close to industrial levels, but projections for these sectors show a marked departure from this trend with commercial sales eclipsing residential energy sales in approximately 2012.[72]

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[69] FERC – Federal Energy Regulatory Commission. 2007. *Assessment of Demand Response and Advanced Metering 2007.* Staff Report. Federal Energy Regulatory Commission, Washington, D.C. Accessed July 20, 2010 at http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf (undated webpage).

[70] EIA – Energy Information Administration. 2010a. "Table 8.13: Electric Utility Demand-Side Management Programs, 1989-2008." *Annual Energy Review 2009*. Energy Information Administration, Washington, D.C. Accessed October 26, 2010 at http://www.eia.gov/emeu/aer/elect.html (last updated August 19, 2010).

[71] EIA – Energy Information Administration. 2010b. *Electric Power Annual with Data for 2008*. Energy Information Administration, Washington, D.C. Accessed June 23, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (last updated January 21, 2010).

[72] EIA – Energy Information Administration. 2008. *Annual Energy Outlook 2008*. DOE/EIA-0383(2008), Energy Information Administration, Washington, D.C. Accessed July 20, 2010 at http://www.eia.doe.gov/oiaf/archive/aeo08/index.html (last updated June 2008).

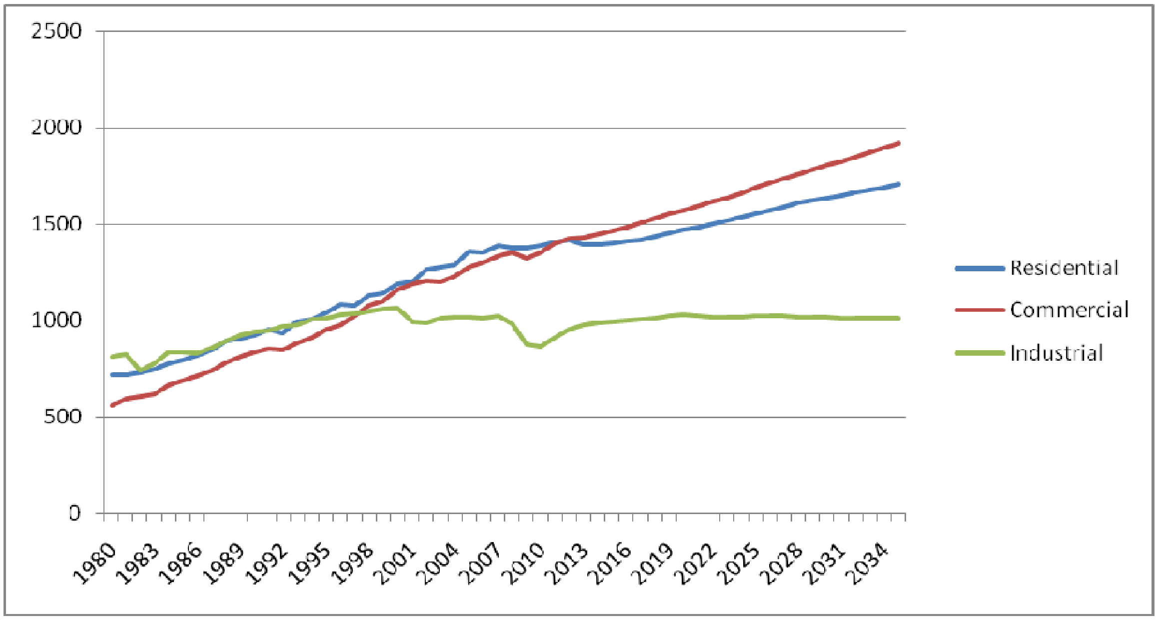


**Figure A.11**. Annual Electricity Sales by Sector, 1980 to 2035 (billion kWh)[73,74]

According to a 2008 FERC Survey,[75] only about 8 percent of customers have a time-based rate or are involved in some form of a demand response program. Based upon estimates in the 2009 FERC Assessment, there were approximately 7.95 million installed advanced meters across the United States.[76] Two other independent analyses indicate that approximately 16 million smart meters were installed in 2010.[77,78] These two estimates indicate that smart meters are present in approximately 10.7 percent of the market. Results from a 2008 FERC report indicate that the number of entities offering demand response and load management programs is small, with direct load control (DLC) and interruptible/curtailable tariffs listed as the most common incentive-based programs (Table A.4).

[73] EIA – Energy Information Administration. 2010c. "Table 8. Electricity Supply, Disposition, Prices, and Emissions." *Annual Energy Outlook 2010*. Energy Information Administration, Washington, D.C. Accessed October 22, 2010 at http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_8.xls (undated webpage).

[74] EIA – Energy Information Administration. 2010d. "Table 8.9. Electricity End Use, 1949-2009." *Annual Energy Review 2009.* Energy Information Administration, Washington, D.C. Accessed January 17, 2011 at http://www.eia.gov/emeu/aer/elect.html (last updated August 19, 2010).

[75] FERC – Federal Energy Regulatory Commission. 2008. *Assessment of Demand Response and Advanced Metering.* Staff Report, December 2008. Federal Energy Regulatory Commission, Washington, D.C. Accessed November 6, 2008 at http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf (undated webpage).

[76] FERC – Federal Energy Regulatory Commission. 2009. *Assessment of Demand Response and Advanced Metering.* Staff Report, September 2009. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/sep-09-demand-response.pdf (undated webpage).

[77] Neichin G and D Cheng. 2010. *2010 U.S. Smart Grid Vendor Ecosystem: Report on the Companies and Market Dynamics Shaping the Current U.S. Smart Grid Landscape*. Cleantech Group LLC. Accessed September 29, 2010 at http://www.energy.gov/news/documents/Smart-Grid-Vendor.pdf (undated webpage).

[78] King C. 2010. Email from Chris King (EMeter Corporation) to Patrick Balducci (Pacific Northwest National Laboratory), "Secretary Chu Off By 14 Million Smart Meters," September 1, 2010, Portland, Oregon.

**Table A.4**. Entities Offering Load-Management and Demand-Response Programs[79]

| Type of Program | Number of Entities |
|---|---|
| Direct Load Control | 209 |
| Interruptible/Curtailable | 248 |
| Emergency Demand-Response Program | 136 |
| Capacity-Market Program | 81 |
| Demand Bidding/Buyback | 57 |
| Ancillary Services | 80 |

In a recent Notice of Proposed Rulemaking issued by FERC[80] regarding wholesale competition, four new incentive-based demand-response proposals were issued:

- Allow demand-response resources to provide services such as supplemental reserves and to correct generator imbalances in RTO/ISO markets when they meet the technical requirements.
- During emergencies, eliminate excess charges when using less energy than was purchased in the day-ahead market.
- Allow an organization that aggregates demand response to bid into organized markets on behalf of their retail customers.
- Include provisions that allow market power rules to be modified when demand is approaching available supply.

### A.5.2 Description of Metric and Measurable Elements

The following metric identifies the most important factor in understanding and quantifying managed load:

1. (Metric 5) Fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives—the load reduction as a percentage of net summer capacity.

### A.5.3 Deployment Trends and Projections

Currently, load participation does exist and many organizations such as the ERCOT, Public Utility Commission of Texas (PUCT), and the California and New York ISOs act to balance and curtail loads to avoid and manage brownouts and blackouts. Nationally, however, demand-response participation is very low. Figure A.12 illustrates that load management was

[79] FERC 2008.

[80] 18 CFR 35. 2008. "Wholesale Competition in Regions with Organized Electric Markets. Notice of Proposed Rulemaking." *Code of Federal Regulations*, Federal Energy Regulatory Commission. Accessed July 20, 2010 at http://www.ferc.gov/whats-new/comm-meet/2008/022108/E-1.pdf (undated webpage).

1.3 percent of net summer capacity in 2008. Figure A.13 shows the participation rate in terms of MW based on EIA data.

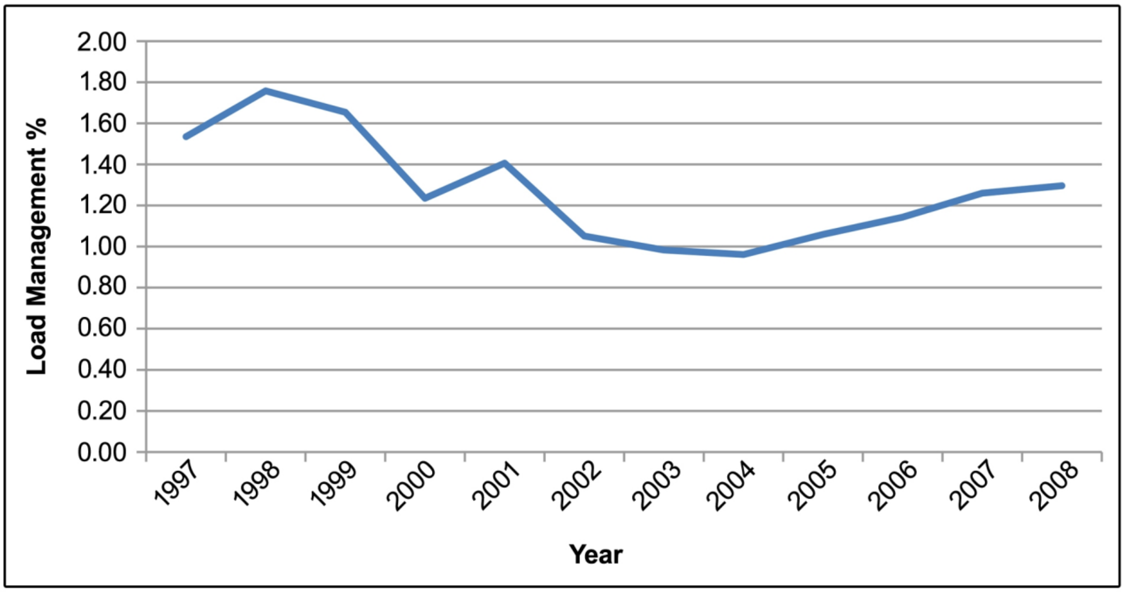


**Figure A.12**. Historic Load-Management Peak Reduction as a Percentage of Net Summer Capacity[81,82]

[81] EIA – Energy Information Administration. 2010c. "Table 8.11a: Electric Net Summer Capacity: Total (All Sectors), 1949-2009." *Annual Energy Review 2009*. DOE/EIA-0384(2009), Energy Information Administration, Washington, D.C. Accessed June 25, 2010 at http://www.eia.gov/emeu/aer/elect.html (last updated August 19, 2010).

[82] EIA – Energy Information Administration. 2010d. "Table 9.1." *Electric Power Annual with Data for 2008*. Energy Information Administration, Washington, D.C. Accessed June 25, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile9_1.xls (undated).

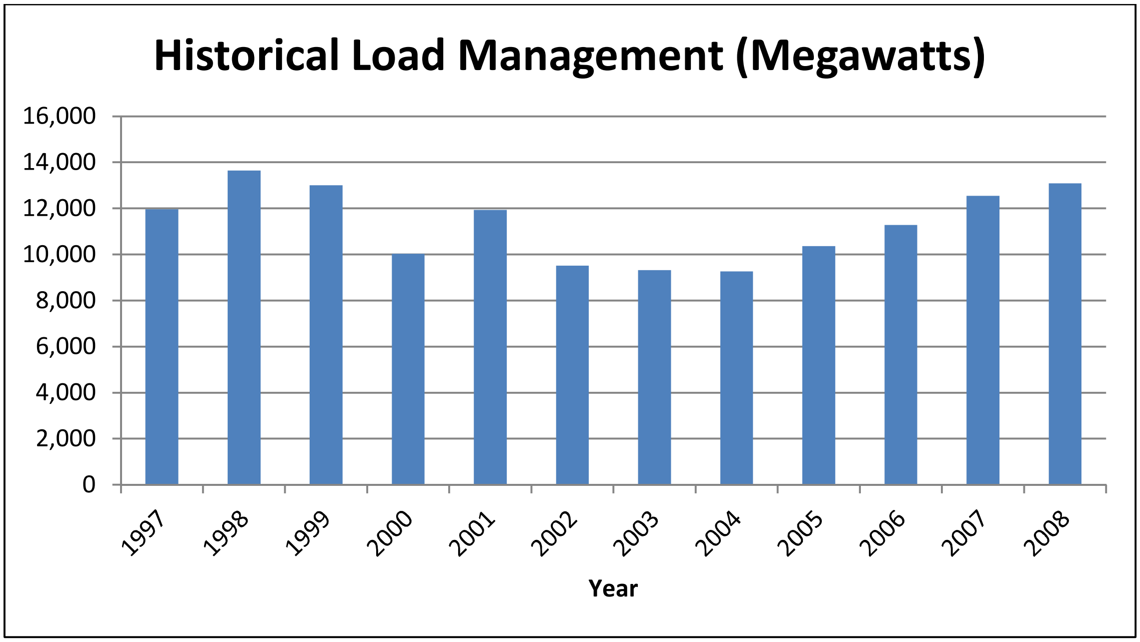


**Figure A.13**. National Historic Demand-Response and Load-Management Peak Reduction in MW[83]

From these graphs it is clear that load management has not played a strong role in energy markets. Nationally, load management as a percent of net summer capacity has declined from 1.5 percent in 1997 to 1.3 percent in 2008. The trend has been somewhat volatile over the past decade, but appears to have been moving upward since 2003. FERC reported in their 2008 Survey that approximately 8,032 MW of interruptible load plus 11,045 MW of direct load control were available.[84] Thus, approximately 2 percent of net summer capacity is under direct load control or interruptible tariffs. This differs from values provided by EIA, which are shown in Figure A.13.

The Electric Power Research Institute (EPRI) expects the effect of demand-response programs to be low at least until 2030, with demand response accounting for a reduction of less than 0.1 percent of the base load in the base case for 2030, and with 5 percent as an "aggressive" target.[85] The 2009 FERC Assessment study projects that the effects of demand-response programs under its business-as-usual case would be higher, reducing peak demand by as much as 38 GW by 2019, a 4 percent reduction, or as much as 188 GW, or 20 percent, reduction from peak demand under the full-participation scenario.[86]

[83] EIA 2010d.
[84] FERC 2008.
[85] Amarnath A. 2008. *Heat Pump Water Heaters: Demonstration Project*. Presented at the ACEE Forum on Water Heating and Use. June 1-3, 2008, Sacramento, California. Electric Power Research Institute. Accessed July 20, 2010 at http://old.aceee.org/conf/08whforum/presentations/4a_amarnath.pdf (undated webpage).
[86] FERC 2009.

This metric measures the fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives. Interviews conducted for this report (see Appendix B) indicated little development of load control and customer participation in demand-response programs. Those replying to the question “Do you have remote load control of customer high energy devices?” responded as follows:

- Six companies (25 percent) indicated they had no remote load control.
- Eight companies (33.3 percent) reported that such systems were in development.
- Eight companies (33.3 percent) indicated a small amount of remote load control (< 10 percent) of customer devices.
- One company (4.2 percent) reported significant remote load control (10 to 70 percent) of customer devices.
- One company (4.2 percent) reported complete (> 70 percent) direct load control of customer devices.

Companies responding to the question “Do you have customer participation in demand response (DR)?” indicated that:

- Four companies (16.7 percent) have no customer participation.
- Six companies (25 percent) have programs in development.
- Twelve companies (50 percent) indicated that there is a small amount (< 10 percent) of customer participation in DR.
- One company (4.2 percent) reported a significant amount (10 to 70 percent) of customer participation in DR.
- One company (4.2 percent) indicated complete (> 70 percent) customer participation in DR.

#### A.5.3.1 Associated Stakeholders

Stakeholders include the following:

- end users (consumers) – residential, commercial, industrial; with the advent of more incentives by distribution and transmission providers, the amount of load managed could rise significantly and end users will have more supply options and incentives to improve energy efficiency
- electric-service retailers – regulated and unregulated electricity providers, who provide energy services based on market incentives and supply
- local, state, and federal energy policy makers – will need to evaluate the effects of current regulations on demand response

- transmission providers – provide and/or recognize response programs for transmission of electricity
- distribution providers – will provide incentive programs to encourage demand response
- generation and demand wholesale-electricity traders/brokers – manage the generation required to meet load net of demand response
- product and service providers – provide the communication technologies that will provide supply and demand information to providers, transmitters, and end users.

#### A.5.3.2 Regional Influences

Regional influences should not create significant obstacles to load participation. However, there are a few regional considerations that may create difficulties in analysis when aggregating regional data to the state and national level. For example, differences in the frequencies of load and demand measurements (seconds, minutes, hours, days) may introduce interpolation or extrapolation errors. This could be especially true for regions that find it difficult or expensive to monitor and/or communicate such data, such as sparsely populated rural areas with poor wireless-communication coverage. Further, regional differences in load participation levels will vary both in terms of time of day and volume. For example, regions in the Pacific time zone will experience their typical on-peak hours one hour later than regions in the Mountain time zone, and the volume of the participating load may vary significantly from one region to another. Demand response levels vary significantly by NERC region. Direct load control is much higher in FRCC than in other areas (see Figure A.14). In the Midwest Reliability Organization, interruptible demand is much higher (3.0 percent of internal demand) than in other regions (less than 2.0 percent of internal demand).

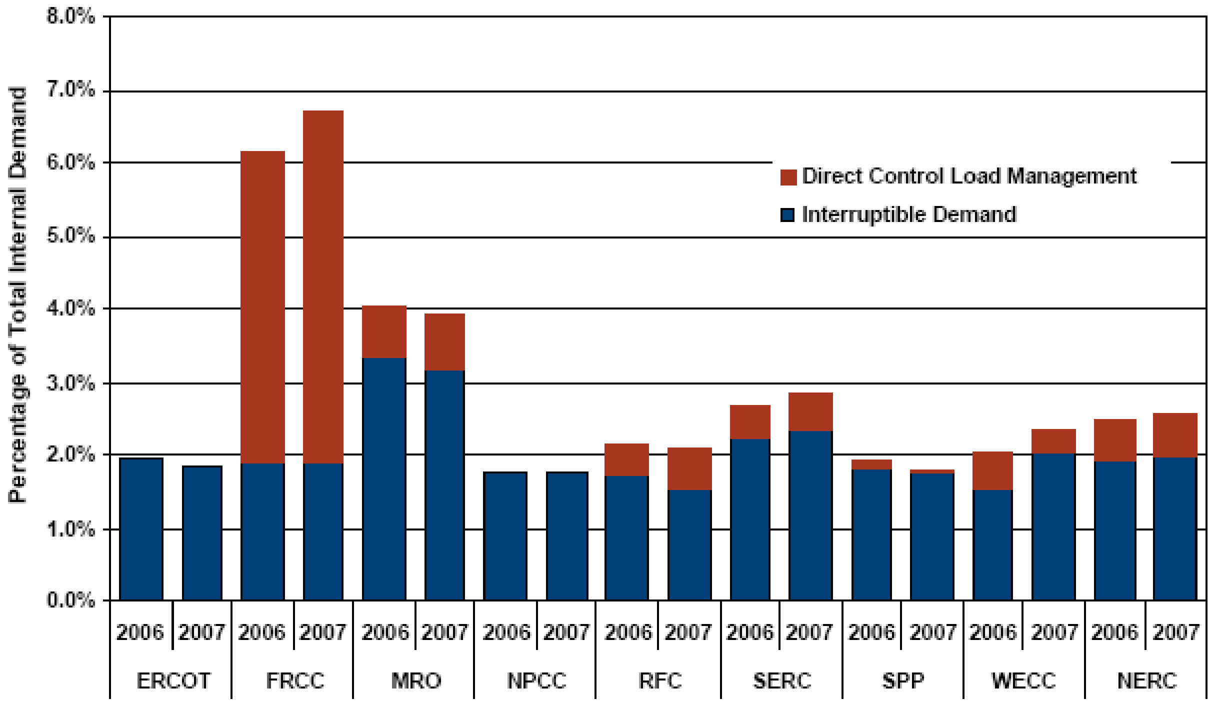


**Figure A.14**. Demand Response by NERC Region[87]

## A.5.4 Challenges to Deployment

The technical, business and financial, and policy challenges to demand participation follow.

### A.5.4.1 Technical Challenges

Literature reviewed for this report identified a "lack of third-party access" to usage data as well as "insufficient market transparency"[88] as key barriers to developing functional demand response programs.

Timely access to meter data and communication infrastructure, probably from advanced-metering systems, is vital to supplying the energy market with the data necessary to track energy prices, estimate and execute demand-response measures, and provide consumers and suppliers with accurate, real-time data. A deployment that does not consider methods of

[87] FERC 2007, p. C-1.

[88] FERC – Federal Energy Regulatory Commission. 2006. *Assessment of Demand Response & Advanced Metering*. Staff Report, Docket Number AD-06-2-000, August 2006. Federal Energy Regulatory Commission, Washington, D.C. Accessed July 20, 2010 at http://www.ferc.gov/legal/staff-reports/demand-response.pdf (undated webpage).

increasing data availability and market transparency risks failing to provide sufficient price information to consumers, demand information to producers, and market information to innovators.[89]

In addition to data availability, considerable data infrastructure improvements will be required to collect and support the necessary data accessibility.[90] Smart metering used to collect the data required for operating a functional demand-response program will require that extensive volumes of data be sent back to the electricity service provider on regular intervals. Data from smart meter readings on 15-minute intervals require approximately 400 megabytes (MB) of data storage per smart meter annually, or 200 terabytes (TB) per year for 500,000 meters (including data redundancy for disaster recovery).[91] Nationally, at a rate of 400 MB per year (using 15-minute intervals), if every electricity customer had an advanced meter, the data needs of the smart grid would be 57.3 petabytes (PB) of data storage per year.

Additional technical considerations include standardization of metering, and/or appliance timers and communication equipment, i.e., "plug and play," and methods for communicating data from household meter to electricity service provider company. Demand-response programs need to address the lack of electricity service provider signals that reflect their needs. Further technical issues could include incorporation of local and regional objectives that could be addressed only through customization of demand-response programs. Another technical issue could be the use of installed equipment for persistent control rather than for emergency curtailment. Demand-response programs will also need to be able to regulate loads up or down to accommodate intermittent renewable resources.[92] Also, development of more spinning reserves and localized dispatch for distribution capacity management are needed to accommodate increasing levels of demand response.

#### A.5.4.2 Business and Financial Challenges

The expense of increasing load participation comes from both the supply and demand sides of the market. Companies may need to invest in new load-management programs and/or refine current SCADA techniques. Further costs of developing and installing hundreds of

[89] FERC 2006.

[90] Miller J. 2009. *The Smart Grid – Some Technical Challenges*, p. 35. Presented at the Symposium on Modeling & Control of Alternative Energy Systems. April 2, 2009, Washington, D.C. Accessed July 12, 2010 at http://www.smartgridinformation.info/pdf/1414_doc_1.pdf (undated webpage).

[91] Pariseau B. May 1, 2009. "Energy IT Sees Smart-Grid Boon for Data Storage." *SearchStorageChannel.com*. Accessed July 12 2010 at http://searchstoragechannel.techtarget.com/news/article/0,289142,sid98_gci1355355_mem1,00.html (last updated May 1, 2009).

[92] Callahan SJ. 2007. "Smarter Meters Require Open Standards." *Electric Light and Power*. Accessed July 20, 2010 at http://www.elp.com/index/display/article-display/284514/articles/electric-light-power/volume-85/issue-1/sections/news-analysis/smarter-meters-require-open-standards.html (undated webpage).

thousands to millions of units of load-management and demand-response equipment, be that some form of advanced metering or otherwise, represent large investments of capital that must be raised and recovered, and may pose a significant challenge to electricity service provider companies.[93]

On the demand side, customers need to be educated about the potential savings (or earnings) from their participation. Additionally, they will need simple, user-friendly enabling technologies that inform them of grid events (electricity prices, shortages, etc.) and allow them to operate their electrical loads in accordance with these events.

### A.5.5 Metric Recommendations

More information from the EIA on the content of the load management variable would be useful. Form 861 does not provide a clear definition of what is measured. In addition, more information on the applicability or response to the total population from FERC in its demand response survey could provide further insights into the amount of load that is actually being captured.

[93] Steklac I. 2007. "AMI: Bridging the Gaps." *Next Generation Power & Energy*, Vol. 1. Accessed July 20, 2010 at http://www.nextgenpe.com/currentissue/article.asp?art=271002&issue=215 (undated webpage).

# A.6 Metric #6: Load Served by Microgrids

## A.6.1 Introduction and Background

Microgrids may change the landscape of electricity production and transmission in the United States due to the changing technological, regulatory, economic, and environmental incentives. The changing incentives could allow the “modern grid” to evolve into a system where centralized generating facilities are supplemented with smaller, more distributed production using smaller generating systems, such as small-scale CHP, small-scale renewable energy sources (RES), and other DERs. The development of new technologies in power electronics, control, and communications,[94] along with the combined values of heat and electricity through cogeneration, added reliability, security, and stability may offset the lower costs of centralized generation.[95]

A microgrid is an integrated distribution system with interconnected loads and distributed energy sources and storage devices, which could be as small as a city block or as large as a small city, and which operates connected to the main power grid, but is capable of operating as an island.[96,97] Key distinctions between a microgrid and distributed generation are the microgrid’s ability to be islanded with coordinated control, and that it contains more than one generating source.[98] However, the distinction between microgrids and larger, isolated grids (such as islands) is not clearly defined at this time.

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[94] Lasseter R, A Akhil, C Marnay, J Stephens, JE Dagle, R Guttromson, A Sakis Meliopoulos, R Yinger, and J Eto. 2002. *White Paper on Integration of Distributed Energy Resources: The CERTS MicroGrid Concept*. LBNL-50829. Prepared for the U.S. Department of Energy, Washington, D.C., and the California Energy Commission, Sacramento, California. Accessed July 20, 2010 at http://www.osti.gov/bridge/servlets/purl/799644-dfXsZi/native/799644.PDF (undated webpage).

[95] Agrawal, P, M Rawson, S Blazewicz, and F Small. July 1, 2006. “How ‘Microgrids’ are Poised to Alter the Power Delivery Landscape.” *Utility Automation & Engineering T&D*. Accessed July 20, 2010 at http://qa.pennenergy.com/index/power/display.articles.utility-automation-engineering-td.volume-11.issue-6.features.how-lsquomicrogridsrsquo-are-poised-to-alter-the-power-delivery-landscape.html (undated webpage).

[96] Lasseter et al. 2002.

[97] Rahman S. 2008. *A Framework for a Resilient and Environment-Friendly Microgrid with Demand-Side Participation.* Advanced Research Institute, Virginia Polytechnic Institute and State University, Arlington, Virginia. Accessed July 20, 2010 at http://www.ceage.vt.edu/media/documents/PES-July08.pdf (undated webpage).

[98] Lasseter RH. 2007. “Microgrids and Distributed Generation.” *Journal of Energy Engineering* 133(3):144-149. Accessed September 16, 2010 at http://www.google.com/url?sa=t&source=web&cd=1&ved=0CBcQFjAA&url=http%3A%2F%2Fciteseerx.ist.psu.edu%2Fviewdoc%2Fdownload%3Fdoi%3D10.1.1.117.8039%26rep%3Drep1%26type%3Dpdf&ei=2GySTLPfEoLEsAPLkNi_Cg&usg=AFQjCNHy5mg7nXlbqafMvH0K2qajSzEHHQ (undated webpage).

In "*Grid 2030*," the DOE identified microgrids as one of three cornerstones of the future grid.[99] Microgrids are seen as local power resources that are connected to the regional grid to provide distributed energy resources while managing local energy supply and demand.[100]

Microgrids will add three features to the electricity system: efficiency; matching of security, quality, reliability, and availability with the end-users' needs; and appearing to the electricity system as a controlled entity.[101] Microgrids may also be better positioned to utilize combined heat and power, which can capture as much as 85 percent of the energy used in generating electricity by also powering heating and cooling systems. In comparison, central grid generation may lose up to 60 percent of the energy used to generate electricity because of losses in transmission and venting heat into the atmosphere. In addition, microgrids can supplement power to the electricity system by injecting power into the central grid during peak periods.[102] Microgrids can also achieve 99.999 percent reliability compared with 99.9 percent reliability for the centralized grid.[103]

A three-phase implementation path was recommended to the DOE for the development of microgrids in 2005. During the first phase, pilot cases examined the ability of microgrids to reduce costs of power and develop technologies to automatically connect/disconnect the microgrid from the central grid. Phase II pilot cases are expected to examine the security and resiliency of microgrids with higher penetration rates, and Phase III will examine a microgrid's ability to export power to the central grid. Each phase will also address regulatory challenges. Phase I will seek to enhance retail competition while providing fair compensation to utilities for investment and services provided. Phase II will focus on cost recovery of security investments, while Phase III will emphasize transparency of costs to end-users, including real-time and

[99] DOE – U.S. Department of Energy. 2003. *"Grid 2030": A National Vision for Electricity's Second 100 Years*. Office of Electric Transmission and Distribution, U.S. Department of Energy, Washington, D.C. Accessed July 20, 2010 at http://www.oe.energy.gov/DocumentsandMedia/Electric_Vision_Document.pdf (undated webpage).

[100] Ye Z, R Walling, N Miller, P Du, and K Nelson. 2005. *Facility Microgrids*. NREL/SR-560-38019, National Renewable Energy Laboratory, Golden, Colorado. Accessed July 20, 2010 at http://www.nrel.gov/docs/fy05osti/38019.pdf (undated webpage).

[101] Marnay C and R Firestone. 2007. *Microgrids: An Emerging Paradigm for Meeting Building Electricity and Heat Requirements Efficiently and with Appropriate Energy Quality*. LBNL-62572, Ernest Orlando Lawrence Berkeley National Laboratory. Presented at the European Council for an Energy Efficient Economy 2007 Summer Study. June 4-9, 2007, La Colle sur Loup, France. Accessed July 20, 2010 at http://eetd.lbl.gov/EA/EMP/reports/62572.pdf (undated webpage).

[102] Center for Public Policy Research in Environment, Energy and Community Well-Being. April 2008. "Reducing Demand, Promoting Efficiency Key to Defusing Electric Rate Increases." *Penn State Policy Notes*. Center for Public Policy Research in Environment, Energy and Community Well-Being, University Park, Pennsylvania. Accessed July 20, 2010at http://www.ssri.psu.edu/policy/GeneralPolicyBrief_0415.pdf (undated webpage).

[103] NC – Navigant Consulting. 2005. *Microgrids Research Assessment Phase 2*. Navigant Consulting, Burlington, Massachusetts. Accessed November 4, 2008 at http://www.electricdistribution.ctc.com/pdfs/Microgrids_Final_Report_102605-DRAFT.pdf (undated webpage).

environmental benefits.[104,105] The Consortium for Electric Reliability Technology Solutions (CERTS) microgrid, a joint demonstration project funded by DOE and the California Energy Commission (CEC) is used to provide research and development experience on technical, business, and regulatory issues associated with microgrids.[106]

Current demonstration-scale microgrid projects include the Center for the Commercialization of Electric Technologies (CCET) Smart Grid Demonstration Project in Texas, which has received $27 million dollars from ARRA. The project intends to deploy 1–3 kW rooftop solar generation and purchase remote wind power in conjunction with battery storage, high building-envelope efficiencies, and a demand response program[107] to demonstrate microgrid feasibility. Another project receiving ARRA funding in Marin County, California, will begin a three-year demonstration that will emphasize the use of software controls in managing large-scale wind and solar generated power. The Marin County Project will begin with only five municipal buildings on the Marin County Civic Center Campus, possibly expanding to incorporate 1,000 commercial buildings and up to 5,000 homes across three Marin County communities in the future.[108] Avista recently selected the city of Pullman, Washington and the Washington State University campus to be a microgrid demonstration site, which is projected to be operational by 2014.[109] Capacity to be installed, or the load being placed onto the microgrid, were not available for either of these demonstration projects. There are many other examples of microgrids at university, petrochemical, and Department of Defense (DoD) sites.[110] Other significant federally funded microgrid projects are presented in Table A.5.[111,112]

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[104] Agrawal et al. 2006.
[105] NC 2005.
[106] DOE – U.S. Department of Energy. Undated. *Advanced Distribution Technologies & Operating Concepts: Microgrids*. Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, Washington, D.C. Accessed July 20, 2010 at http://www.electricdistribution.ctc.com/microgrids.htm (undated webpage).
[107] CCET – Center for the Commercialization of Electric Technologies. Undated. *Department of Energy – Smart Grid Stimulus Awards for Texas*. Accessed October 26, 2010 at http://www.electrictechnologycenter.com/awards.html (undated webpage).
[108] *Smart Grid News.com*. October 30, 2009. "Marin County Microgrid Project Kicks Off." Accessed October 21, 2010 at http://www.smartgridnews.com/artman/publish/Delivery_Microgrids_News/Marin-County-Microgrid-Demonstration-Kicks-Off-1346.html (last updated October 30, 2009).
[109] *WSU Today*. 2009. "Pullman to Become Smart Grid Community." Accessed June 25, 2010 at http://researchnews.wsu.edu/physical/260.html (undated webpage).
[110] RDC 2005.
[111] DOE – U.S. Department of Energy. 2010. *Categorical Exclusions Determinations, Raw Dataset – CX Database*. Accessed October 18, 2010 at http://nepa.energy.gov/documents/CXdbRawData.xls (undated webpage).
[112] SGIC – Smart Grid Information Clearinghouse. 2010. *Smart Grid Projects*. Accessed September 23, 2010 at http://www.sgiclearinghouse.org/?q=node/13 (undated webpage).

**Table A.5**. Federally Funded Microgrid Projects

| Project | State | City | Description |
|---|---|---|---|
| Pecan Street Project Energy Internet Demonstration | TX | Austin | The recipient will develop and implement an energy internet microgrid located in a large mixed-use infill development site in Austin, Texas. |
| San Diego Gas and Electric Borrego Springs Microgrid Demonstration | CA | Borrego Springs | The recipient will install and operate Home Area Network devices on 125 homes (exact homes to be determined) in the Borrego Springs community. It will also modify or replace equipment along existing electricity service provider rights-of-way. Finally, it will install and operate an electricity-service-provider-scale diesel generator, batteries and related equipment, and components within the existing Borrego Springs substation.[113] |
| Allegheny Power | WV | Morgantown | The project received $4 million in federal funding to demonstrate advanced operational strategies such as dynamic islanding and microgrid concepts and examine new ways to serve priority loads through the integration of automated load control with advanced system control.[114] |
| Illinois Institute of Technology | IL | Chicago | The project received $7 million in DOE funds to develop an integrated microgrid system capable of full islanding.[115] |

### A.6.2 Description of the Metric and Measurable Elements

The following three measures have been identified as important for understanding the number of microgrids and the amount of capacity they serve.

(Metric 6.a) The number of microgrids in operation. Microgrids must meet the definition in Section 1 above.

(Metric 6.b) The capacity of microgrids in MW.

*(Metric 6.c) The percentage of total grid summer capacity that is served by microgrids*. This metric measures the effect these microgrids are having on the ability of microgrids to meet electricity-supply requirements of the entire grid.

### A.6.3 Deployment Trends and Projections

Currently, approximately 20 microgrids can be found at universities, petrochemical facilities and U.S. defense facilities. According to Resource Dynamics Corporation (RDC),[116] the microgrids provided 785 MW of capacity in 2005. They noted additional microgrids that were in planning at the time as well as demonstration microgrids. RDC also noted that by examining

[113] DOE 2010.
[114] SGIC 2010.
[115] SGIC 2010.
[116] RDC 2005.

the EIA's database they could determine approximately 375 potential additional sites for microgrids. Outside of the petrochemical microgrids, there are no commercial microgrids in the United States.[117] Given EIA's net national summer generating capacity of 1,010,171 MW and assuming no devolution of microgrid capacity from 2005, the percentage of capacity met by microgrids is about 0.08 percent in 2008.[118]

**Table A.6**. Capacity of Microgrids in 2005 (MW)[119]

| | University | Petrochemical | DOD |
|---|---|---|---|
| Capacity (MW) | 322 | 455 | 8 |

Current projections and forecasts for microgrids are as follows:

- Navigant Consulting, in their base-case scenario, projected 550 microgrids installed and producing approximately 5.5 GW by 2020[120] or about 0.5 percent of projected summer capacity.[121] Navigant[122] predicts a range of 1 to 13 GW depending on assumptions about pushes for more central power, requirements and demand for reliability from customers, and whether there is an environmental requirement for carbon management. It should further be noted, however, that the considerable range of this prediction suggests the limits to which the present status of microgrids are understood.
- Pike Research estimates that in 2010 there are approximately 626 MW of capacity on microgrids operating in the United States, and anticipates that this will increase to 2.35 GW by 2015. This growth is expected to occur primarily in the Commercial, Industrial, and Institutional/Campus sectors.[123]

#### A.6.3.1 Associated Stakeholders

There are numerous stakeholders associated with microgrids, but the primary stakeholders include

[117] Center for Public Policy Research in Environment, Energy and Community Well-Being 2008.
[118] EIA – Energy Information Administration. 2010. *Electric Power Annual with Data for 2008*. Energy Information Administration, Washington, D.C. Accessed September 16, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (last updated January 21, 2010).
[119] RDC 2005.
[120] NC 2005.
[121] EIA – Energy Information Administration. 2008. *Annual Energy Outlook 2008*. DOE/EIA-0383(2008), Energy Information Administration, Washington, D.C. Accessed July 20, 2010 at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html (last updated June 2008).
[122] NC 2005.
[123] Pike Research. 2009. *Microgrids: Islanded Power Grids and Distributed Generation for Community, Commercial, and Institutional Applications*. Pike Research, Boulder, Colorado. Accessed June 23, 2010 at http://www.missioncriticalmagazine.com/MC/Home/Files/PDFs/WP-MICROPike_Research-ExecutiveSummary.pdf (undated webpage).

- end-users, including distributed-generation owners and customers, who need reliable, high quality power; offsetting costs by selling excess power and/or heat has the potential to make programs more economical and attractive
- distribution-service providers, as well as utilities and municipalities, who, depending on their size, location, and ability to integrate microgrid power production, could significantly benefit from integration of microgrid resources into their overall resource portfolio
- electric-service retailers
- products-and-services suppliers of generation, control, and communications equipment that enable microgrid operation
- policymakers
- policy advocates, particularly environmental policy advocates.

#### A.6.3.2 Regional Influences

Regional influences should not create significant obstacles for microgrid development. Potential regional influences are driven more by how stakeholders in different regions of the country will interface or integrate with one another, and how regional or state regulators in the electricity service provider and environmental areas will either support or hinder development of distributed energy resources.

Microgrids can be favorable in remote places such as Alaska and Hawaii, where significant periods of islanded operation can be expected. Microgrids with CHP may be of greater value in colder climates (northern states) or regions where heating and cooling requirements are significant.

### A.6.4 Challenges to Deployment

Unfortunately, several barriers have been identified that may stifle the deployment of microgrid systems in the United States. As in other industries, regulatory barriers and their economic effects are more significant challenges to deployment than the technical challenges. While there are several regulatory barriers, the business and financial challenges listed below are those with the highest impact.

#### A.6.4.1 Technical Challenges

While the business and financial challenges are more significant, there are technical challenges to moving microgrid deployments forward. The primary technical challenges include:

- interconnection – Interconnection requirements must be resolved through standards such as IEEE 1547.4; otherwise seamless transitions will not occur.[124] Completion of the IEEE 1547.4 standard for microgrid requirements is also needed.[125]
- integration – Integrating large volumes of distributed generation resources and managing the variability of their generation while still maintaining compliance with the FERC-approved Reliability Standards.[126]
- large-scale microgrids – As the interconnection points increase, large microgrids with multiple points of integration become more complicated to coordinate and protect.[127]
- penetration level – The level of penetration could become an issue if the load served by microgrids becomes large enough that they are serving more than their own demand, and system events such as lightning strikes or other system failures cause the microgrid to respond by disconnecting from the regional grid, leaving other dependent entities without power.[128]
- security – Some concern exists regarding the level of security, both physical and cyber, required for microgrids to be a reliable resource.[129]
- reliability – Distributed energy storage and generation hardware should not require extensive maintenance. Ideally, distributed microgrid components will be on maintenance cycles that are in line with other hardware at the installations.[130]
- power generation types – For alternative-energy resources such as renewable energy, fuel cells, and microturbines, the lack of experience with system design and integration will provide technical challenges.[131,132]

[124] NC 2005.**Error! Hyperlink reference not valid.**
[125] IEEE – Institute of Electrical and Electronics Engineers. 2008. *1547 Series of Standards*. Institute of Electrical and Electronic Engineers. Accessed July 20, 2010 at http://grouper.ieee.org/groups/scc21/dr_shared/ (last updated June 14, 2010).
[126] 18 CFR Chapter I. 2009. "Smart Grid Policy." *Code of Federal Regulations*, Federal Energy Regulatory Commission.
[127] Ye et al. 2005.
[128] Ye et al. 2005.
[129] NETL – National Energy Technology Laboratory. 2007. *Barriers to Achieving the Modern Grid*. Prepared by National Energy Technology Laboratory for the Office of Electricity Delivery and Energy Reliability, U.S. Department of Energy, Washington, D.C. Accessed July 20, 2010 at http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/Barriers%20to%20Achieving%20the%20Modern%20Grid_Final_v1_0.pdf (undated webpage).
[130] Stevens J and B Shenkman.2009. *DC Energy Storage in the CERTS Microgrid.* Sandia National Laboratories, Albuquerque, New Mexico. Accessed June 28 2010 at http://certs.lbl.gov/pdf/microgrid-dc-storage.pdf (undated webpage).
[131] Ye et al. 2005.
[132] NC 2005.

- power quality – Power quality may be affected by current IEEE 1547 standards, as microgrids may be forced off the grid when power instability events occur. Power quality in the microgrid is a function of its size, impedance, and load level.[133]
- intentional islanding – The transition between regional grid-parallel and isolated operation can leave microgrids without power for periods from seconds up to minutes. The impact on loads within the microgrid due to transient effects or disruption isn't acceptable; a more instantaneous transition is required.[134]

#### A.6.4.2 Business and Financial Challenges

The most significant business and financial challenge is making the business case for microgrids. A part of the business case includes ensuring that microgrids are not made infeasible by standby charges, interconnection policies that discourage or prohibit microgrids, and the loss of revenues faced by utilities as microgrids are deployed. But the business case must also be effectively shown for the value of combined heat and electricity generation, added security, reliability, and power quality in order for investment to take place.[135] Significant challenges to the business case include:

- standby charges – Charges assessed to end-users on their installed capacity if it is not used solely for emergency purposes. Utilities use the standby charge to pay for the infrastructure necessary to serve the microgrid's load in the event the microgrid's generating capability becomes unavailable. These charges for rarely used infrastructure represent an economic barrier to microgrid deployments.[136,137]
- interconnection – The policies and procedures that describe how power-generating capacity not owned by the electricity service provider will be connected and integrated into the power grid. Without national or regional policies and procedures, utilities can develop their own policies and procedures that discourage interconnection of power-generating capacity that they do not own or control.[138] (See Metric 3.)
- lost electricity service provider revenues – The way the U.S. utilities are regulated, they exhibit strong economies of scale that make competition from smaller, less-efficient suppliers significantly less economical. In addition, utilities have no financial motivation to

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[133] NC 2005.
[134] Ye et al. 2005.
[135] NC 2005.
[136] Hatziargyriou N. 2008. "Microgrids: the Key to Unlock Distributed Energy Resources?" IEEE Power Engineering Society, Piscataway, New Jersey. Accessed July 20, 2010 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=04505823 (undated webpage).
[137] Venkataramanan G and C Marney. 2008. "A Larger Role for Microgrids: Are Microgrids a Viable Paradigm for Electricity Supply Expansion?" *IEEE Power and Energy Magazine*, May/June 2008, pp.78-82. Accessed July 20, 2010 at http://eetd.lbl.gov/EA/EMP/reports/microgrids-larger-role.pdf (undated webpage).
[138] Venkataramanan and Marney 2008.

look at grid innovations that reduce their sales. Utilities have commonly raised barriers to interconnection and self-generation and also discourage energy efficiency investments because of the significant likelihood of a loss of revenue and profits.[139]

### A.6.5 Metric Recommendations

The number and capacity (MW) of microgrids needs to be added as a sub-category of distributed generation (DG) where DG can be islanded and controlled to allow for the enumeration and quantification of microgrids. Present metrics remain difficult to evaluate or quantify on an annual or biennial basis; therefore, it may be beneficial to reevaluate the metrics presently used, to facilitate a more accurate accounting of the present status of microgrids.

[139] Venkataramanan and Marney 2008.

# A.7 Metric #7: Grid-Connected Distributed Generation and Storage

## A.7.1 Introduction and Background

This metric measures the quantities and types of distributed-generation and energy-storage equipment that are connected to the grid. Distributed-generation systems are different from the large and centralized generators that provide most of the grid's power. Rather, DG systems are noted for their smaller-scale local power generation (10 MVA or less), which can be connected to primary and/or secondary distribution voltages.[140] Solar cells, wind turbines, and biomass applications are some of the types of distributed generation available to residential and rural consumers.

This metric also covers energy storage devices such as batteries, flywheels, and thermal storage units that could be used to store energy.

## A.7.2 Description of Metric and Measurable Elements

The electricity from service providers can be at least partially offset through the deployment of distributed generators. With net metering, excess power generated by the customer can be sold back to the electricity service provider and credited back to the customer's account. Electricity sold or stored from DG will be classified into one of six categories: internal combustion, combustion turbine, steam turbine, hydroelectric, wind, and other. The metrics should not include DG or storage that is not actively managed and is not interconnected with the grid, or is available for emergency capacity only, or is considered a microgrid. Measures could distinguish important new technologies as they help even-out required dispatchable generation. This would include storage that enables time-varying voltage regulation. At this time there are few storage options.

The following three metrics have been identified as important aspects for understanding and quantifying grid-connected distributed generation and storage.

*(Metric7.a) Percentage of actively managed fossil-fired, hydrogen, and biofuels distributed generation.* This metric excludes DG that is not actively managed and is not interconnected with the grid and excludes emergency, backup generation capacity that is only operated when there is an outage. The DG must be connected to the distribution system or distribution

[140] IEEE – Institute of Electrical and Electronics Engineers. 2003. *IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems*. Institute of Electrical and Electronics Engineers. Accessed October 8, 2010 at http://grouper.ieee.org/groups/scc21/1547/1547_index.html (last updated June 14, 2010).

substation to qualify. Both installed MW and supplied MWh are measured as a percentage of total DG and total grid generation capacity/supply.

*(Metric7.b) Percentage of actively managed batteries, flywheels, and thermal storage excluding transportation applications*. Both MW and MWh would be measured as a percentage of total storage and total grid generation capacity/supply.

*(Metric7.c) Percentage of non-dispatchable distributed renewable generation.* This metric consists of non-dispatchable, non-controllable DG fueled from renewable sources. This metric excludes renewable DG capacity not connected to the grid. Both MW and MWh would be measured as a percentage of total DG and total grid generation capacity/supply.

### A.7.3 Deployment Trends and Projections

Distributed generation capacity has been a small part of total power generation. However, it has been steadily increasing over the years. While in 2004 the total distributed generation capacity was 5,423 MW, it increased to 12,863 MW in 2008, an increase of 137 percent[141] (see Figure A.15). However, in 2008, electricity generation and sales were adversely affected by the weakening economy. Annual net electric power generation decreased for the first time since 2001, dropping 0.9 percent from 4,157 million MWh in 2007 to 4,119 million MWh in 2008. Summer peak load (non-coincident) fell by 3.8 percent, from 782,227 MW in 2007, to 752,470 MW in 2008. Winter peak load (non-coincident), which is always smaller than summer peak load, increased in 2008 by 0.9 percent, from 637,905 MW in 2007, to 643,557 MW in 2008.[142]

[141] EIA – Energy Information Administration. 2010a. *Electric Power Annual with Data for 2008*. Energy Information Administration, Washington, D.C. Accessed July 18, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (last updated January 21, 2010).

[142] EIA 2010a.

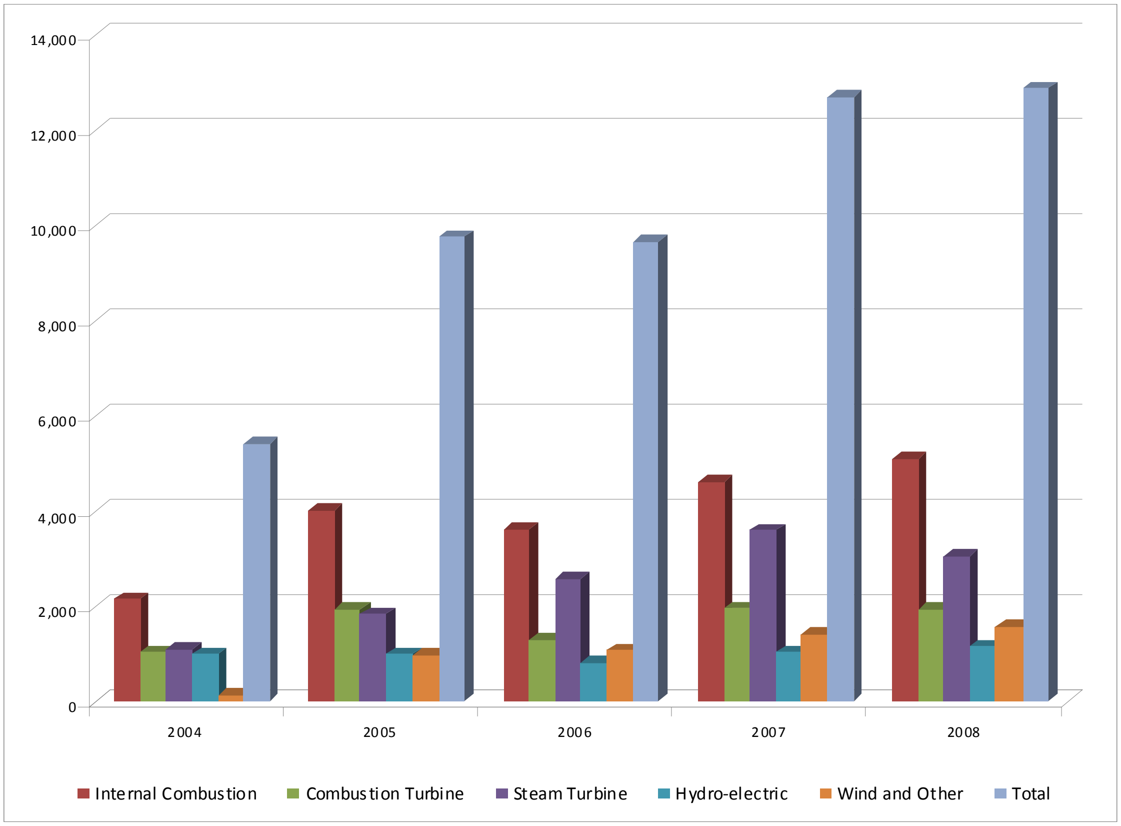


**Figure A.15**. Yearly Installed DG Capacity by Technology Type[143]

The data reported in Figure A.15 was revised by the EIA in 2008 from the figures reported by them in 2007. Distributed generation capacity from actively managed fossil-fired, hydro, and biofuels reached 10,121 MW in 2008, up 136 percent from 2004. This represented approximately 1.27 percent of total generating capacity and 78 percent of total DG. Wind and other renewable energy sources grew significantly between 2004 and 2008, increasing by 1,051 percent, yet they only represent 0.16 percent of total available generating capacity, 0.21 percent of summer peak capacity, and 0.24 percent of winter peak.[144] Distributed wind is very small in comparison to central wind farms, which collectively registered nearly 23,000 MW of capacity. Intermittent renewable-energy resources such as wind may not be effective countermeasures for peak demand reduction, although solar has the potential to be more coincident with summer peak-demand periods.

[143] EIA – Energy Information Administration. 2010b. "Tables 1.6.A-1.6.C: Capacity of Distributed Generators by Technology Type, 2004 Through 2008." *Electric Power Annual 2008*. DOE/EIA-0348(2008), Energy Information Administration, Washington, D.C. Accessed July 18, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/epaxlfile1_6_b.pdf (undated webpage).

[144] EIA 2010b.

**Table A.7**. Yearly Installed DG Capacity by Technology Type[145]

| Capacity of Distributed Generators by Technology Type, 2004 through 2008(Count, Megawatts) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | Internal Combustion | Combustion Turbine | Steam Turbine | Hydro-electric | Wind and Other | Total | |
| Period | Capacity | Capacity | Capacity | Capacity | Capacity | Number of Units | Capacity |
| 2004 | 2,169 | 1,028 | 1,086 | 1,003 | 137 | 5,863 | 5,423 |
| 2005** | 4,024 | 1,917 | 1,831 | 998 | 994 | 17,371 | 9,766 |
| 2006 | 3,625 | 1,299 | 2,580 | 806 | 1,078 | 5,044 | 9,641 |
| 2007 | 4,614 | 1,964 | 3,595 | 1,053 | 1,427 | 7,103 | 12,702 |
| 2008 | 5,112 | 1,949 | 3,060 | 1,154 | 1,588 | 9,591 | 12,863 |

** Distributed generator data for 2005 includes a significant number of generators reported by one respondent that may be for residential applications.
Note: Distributed generators are commercial and industrial generators that are connected to the grid. They may be installed at or near a customer's site, or elsewhere. They may be owned either by customers or by the electricity service provider. Other Technology includes generators for which the technology is not specified.

While DG systems have large startup costs for customers, some technologies, such as solar panels, can be easily installed on rooftops by homeowners and safely generate power for years. Solar power installed in this way has a cost of $6 per watt.[146] The costs for DG technology are expected to fall by 10 percent for the first three capacity doublings, then fall by 5 percent for the next five doublings. After this point, projected costs fall by 2.5 percent for all following capacity doublings.[147]

Thermal storage projects are also taking off, with DOE awarding a contract in June 2010 to the company Sener.[148] In addition, NERC reported that more than 39 pumped storage projects were operating in the United States. Compressed air is being considered in Iowa using caverns. In addition, flywheel technologies are being deployed to supply short periods of load following and regulation services.[149] More companies are also planning thermal storage projects which can reduce peak demand during high usage periods. Office buildings, retail space, and medical

[145] EIA 2010b.
[146] NREL – National Renewable Energy Laboratory. 2010. *Energy Technology Cost and Performance Data*. Accessed November 4, 2010 at http://www.nrel.gov/analysis/tech_costs.html (last updated August 6, 2010).
[147] Eynon RT. 2002 *The Role of Distributed Generation in U.S. Energy Markets.* Energy Information Administration, Washington, D.C. July 18, 2010 at http://www.eia.doe.gov/oiaf/speeches/dist_generation.html (undated webpage).
[148] *RenewableEnergyWorld.com*. June 8, 2010. "Sener Awarded DOE Contract for CSP Thermal Storage System." Accessed July 10, 2010 at http://www.renewableenergyworld.com/rea/news/article/2010/06/sener-awarded-doe-contract-for-csp-thermal-storage-system (last updated June 8, 2010).
[149] NERC – North American Electric Reliability Corporation. 2010. *2010 Long-Term Reliability Assessment*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed January 17, 2011 at http://www.nerc.com/files/2010%20LTRA.pdf (undated webpage).

facilities offer the greatest potential in cost savings. For example, the Dallas Veterans Affairs Medical Center installed an approximately 25,000 ton per hour thermal energy storage unit for $2.2 million and saved approximately $225,000 annually.[150] Most storage technologies face barriers relating to cost effectiveness.[151]

#### A.7.3.1 Associated Stakeholders

Associated stakeholders include:

- end-users (customers) – Distributed generation technology allows customers to act as both buyers and sellers in the energy market. Customers can save money by substituting their own generational capacity for expensive on-peak electricity[152] or temporarily reduce their household consumption and sell their electricity back into the market at high peak prices.[153] Further, DG technology allows customers to contribute or draw electricity based on environmental standards that they choose. On shorter time scales, storage can assist with balancing and ramping of environmentally friendly, but intermittent, energy resources. If energy deposited into the grid is tracked by source type, consumers can choose to purchase more environmentally friendly energy sources such as wind or solar power, or supply their own "green" power into the market. Additionally, should the grid experience technical problems or an emergency, customers can disconnect from the grid and generate their own power and/or draw from battery-stored reserves.[154]
- distribution service providers or electricity service provider companies – Electricity service provider companies face a different set of risks than end users. While DG offers the grid access to quick and cheap resources that expand grid flexibility and capacity,[155] DG will also require a significant investment of resources to manage the quality of the power being supplied, as well as the purchase of new infrastructure to dispatch DG resources. However, DG can be used as a way to defer capital expansion and facilitate retirement of old units by accommodating peak load conditions.[156]

[150] WSU – Washington State University. 2003. "Energy Efficiency Fact Sheet: Thermal Energy Storage." Cooperative Extension Energy Program, Washington State University, Pullman, WA. Accessed January 17, 2011 at www.energy.wsu.edu/ftp-ep/pubs/engineering/thermal.pdf (undated webpage).
[151] NERC 2010.
[152] Hall J. October 1, 2001. "The New Distributed Generation." *Connected Planet*. Accessed July 21, 2010 at http://connectedplanetonline.com/mag/telecom_new_distributed_generation/ (last updated October 1, 2001).
[153] Cogeneration Technologies. 1999. *Distributed Generation*. Accessed July 21, 2010 at http://www.cogeneration.net/Distributed_Generation.htm (undated webpage).
[154] Congeneration Technologies 1999.
[155] Congeneration Technologies 1999.
[156] EAC – Electricity Advisory Committee. 2008. *Bottling Electricity: Storage as a Strategic Tool for Managing Variability and Capacity Concerns in the Modern Grid*. Electricity Advisory Committee, U.S. Department of Energy, Washington, D.C. Accessed July 5, 2010 at http://www.oe.energy.gov/DocumentsandMedia/final-energy-storage_12-16-08.pdf (undated webpage).

- manufacturers of distributed-generation and storage devices – Suppliers will have a stake in developing lower-cost technologies and making those devices more cost effective.
- balancing authorities – Balancing authorities are important stakeholders as non-dispatchable renewable generation grows as a proportion of total grid generation capacity.
- transmission providers – Transmission providers will also have a stake as distributed generation grows to be a larger proportion of the total generation capacity and they need control for power-quality issues. However, modern power electronics and some electrochemistries have the ability to rapidly charge and discharge. This ability could be used as a means to address the dual goals of increasing effective transmission capacity and improving transmission grid reliability.[157]
- local, state, and federal energy policy makers – May need to develop policies on DG interconnection standards.
- standards organizations and their developers – Will need to respond to policy makers on DG interconnection standards.

#### A.7.3.2 Regional Influences

Different states and regions may have regulations for the quality of the power being sold or how the power is produced. Some states may value DG capacity differently from others and offer different subsidies and/or taxes based on those values. For example, Oregon state law has specific plant site-emissions standards for minor sources emitting pollutants such as $NO_x$, $SO_2$, CO, or particulate matter (PM), whereas Ohio relies on the Best Available Technology (BAT) standard with specific limitations for PM and $SO_2$ based on location, unit type, and size.[158] Please see Metric 3 on DG Interconnection for more details on state interconnection differences. Additionally, in accordance with the U.S. Federal Government's Green Power Purchasing Goal, states tend to offer the most incentives for distributed generation projects that use recognized renewable-energy sources.[159]

### A.7.4 Challenges to Deployment

Distributed generation presents significant technical, business, and legal challenges for the grid. The technical challenges include integrating DG resources while maintaining the level and quality of voltage and workable protection coordination. Business and financial challenges

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[157] EAC 2008.
[158] EEA – Energy and Environmental Analysis, Inc. 2008. *Economic Incentives for Distributed Generation*. Accessed July 5, 2010 at http://www.eea-inc.com/rrdb/DGRegProject/Incentives.html (undated webpage).
[159] DSIRE – Database of State Incentives for Renewables & Efficiency (DSIRE). 2008. *Federal Incentives/Policies for Renewables & Efficiency: U.S. Federal Government - Green Power Purchasing Goal*. Accessed July 5, 2010 at http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=US01R&State=Federal&currentpageid=1 (last updated July 27, 2010).

include the costs to utilities of integrating DG resources and providing a system flexible enough that consumers can afford to recover investments in DG resources.

### A.7.4.1 Technical Challenges

Technical challenges to deployment include:

- standardization of the DG system interface with the grid (see Metric 3)
- operation and control of the distributed generation; DG may also make fault detection more difficult[160]
- planning and design
- voltage regulation.[161]

Of course, both the DG and storage resources being considered here share monitoring and control challenges similar to those identified for demand-response metrics (Metrics 3 and 5).

The system interfaces associated with incorporating DG resources widen significantly from the traditional grid interface. Internal combustion engines, combustion turbines, and small hydropower generation require synchronous or induction generators to convert to the prime source and power frequency. Fuel cells, wind turbines, photovoltaics and batteries require inverters. The challenge is to bring the sources on line while maintaining system voltage and frequency. In addition, the inverters used to transform direct current (DC) power generation units to alternating current (AC) power can increase harmonics in the grid.[162]

Voltage-regulation challenges are greater than just changing the transformer. The problem will include overvoltage issues that can arise due to ungrounded DG-connected generation.[163] DG will also present technical hurdles in terms of frequency, voltage level, reactive power, and power conditioning.[164]

Fault detection and protection may become more difficult with increased distributed generation. Since electricity usually flows from areas of high voltage to low voltage, it may

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[160] Driesen J and R Belmans. 2006. "Distributed Generation: Challenges and Possible Solutions." In *Proceedings of the 2006 IEEE Power Engineering Society General Meeting*. June 18-22, 2006, Montreal, Quebec. Institute of Electrical and Electronics Engineers, Piscataway, New Jersey. Accessed October 22, 2010 at http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=1709099 (undated webpage).

[161] Pai MA. 2002. "Challenges in System Integration of Distributed Generation with the Grid." Presented at the Power Electronics and Fuel Cells Component System Integration Workshop. August 8-9, 2002, University of Illinois, Urbana, Illinois. Accessed October 12, 2010 at http://www.nfcrc.uci.edu/2/FUEL_CELL_INFORMATION/UfFC/PowerElectronics/PDFs/04_Pai_Challenge_Part1.pdf (undated webpage).

[162] Eynon 2002.

[163] Eynon 2002.

[164] Driesen and Belmans 2006.

become more difficult to detect faults with fault current coming from both the main power system and from the DG unit.[165] This technical challenge means that in case of fault detection, DG units usually are removed from the grid first, which could have business impacts as discussed in the next section.

Technical challenges for electricity storage include short lifetimes and environmental issues for batteries and materials properties for flywheels. Flow batteries do have long lifetimes, but they have only seen field trials. Nickel metal hydride batteries also have long lifetimes, but have lower energy density.

Sodium-sulfur batteries have shown promise in electricity service provider applications, but are currently too costly. Additionally, the cycle efficiencies of batteries are in the range of 70 percent to 85 percent, which indicates that 15 to 30 percent of energy stored is lost.[166]

#### A.7.4.2 Business and Financial Challenges

Making the grid compatible with DG systems could be expensive for system operators. System operator investment in equipment that integrates DG, microgrids and storage systems is complicated by the fact that the amount of energy transmitted by many of these technologies is often unknown. Therefore, investment recovery can be limited and uncertain. There will also be a need for instrumentation and communication to make the DG resources dispatchable so that utilities and transmission operators can deal with all the technical issues discussed in the previous subsection. These costs could vary from one electricity service provider to another.[167] Please see Metric 3 for a discussion of the business and financial challenges presented by a lack of standard interconnection agreements.

Energy storage technologies could be used to access a number of value streams, including capital deferral, deployment of expanded intermittent energy sources and renewables, and energy maintenance achieved through islanding (power provided independently from the electricity service provider). To achieve these benefits, however, storage systems in the one- to

[165] Driesen and Belmans 2006.

[166] APS – American Physical Society. 2007. *Challenges of Electricity Storage Technologies.* APS Panel on Public Affairs, Committee on Energy and Environment. American Physical Society, College Park, Maryland. Accessed July 8, 2010 at http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-ElectricityStorageReport.pdf (undated webpage).

[167] OE – Office of Electricity and Energy Reliability. 2008. *Metrics for Measuring Progress Toward Implementation of the Smart Grid: Results of the Breakout Session Discussions at the Smart Grid Implementation Workshop*. June 19-20, 2008, Washington, D.C. Prepared by Energetics Incorporated, Washington, D.C. Accessed October 22, 2010 at http://www.oe.energy.gov/DocumentsandMedia/Smart_Grid_Workshop_Report_Final_Draft_08_12_08.pdf (undated webpage).

four-hour runtime range are needed through improvements in existing technologies or the development of new technologies.[168]

Another financial problem posed by storing energy generated by DG resources is that batteries require a large amount of maintenance, which adds significantly to the overall costs of building DG systems, and thus increases the payback period.[169] Unless and until the marginal cost of a battery is less than or equal to the marginal cost of its time-of-use price, viable payback strategies, such as storing power during off-peak periods and selling energy back during high-priced peak periods, will not be feasible and could reduce DG penetration. This is especially true for green power such as wind and solar generation, which can vary during the day.

Distributed generation can be brought online much more quickly than more traditional utility-sized generation, with lower total capital costs. However, the costs per kW are higher and the overall costs of a kWh produced are usually higher than for grid-supplied base-load power. In addition, with the greater flexibility associated with DG comes the risk of less grid stability. When DG is a relatively small fraction of the grid, its impact is relatively small, but as DG penetration increases, the reliability of the grid could potentially degrade due to voltage fluctuations and reactive-power issues. However, other studies show that when DG is set up properly, greater grid reliability can be achieved since pockets of a smart grid can operate as islands in the event of a total grid collapse. Firms may need to take these considerations into account when evaluating the costs/benefits of buying and providing electricity to their businesses.[170] For example, DG may serve as a hedge against grid price fluctuations or power-quality uncertainty—as prices fluctuate upward with tightening supply-demand balances, or if power quality begins to fall, DG owners may opt to produce their own electricity.[171]

The use of DG will depend upon the supply and price of alternative fuels. Increasing fuel prices for small combustion generators or the intermittent nature of some renewable energy sources may make the economic feasibility of DG fluctuate, and it may not be available to meet short-term needs. However, with flexible pricing schemes, shortfalls in grid-supplied capacity can be mitigated by rising prices.

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[168] EAC 2008.

[169] Foote CET, AJ Roscoe, RAF Currie, GW Ault, and JR MacDonald. 2005. "Ubiquitous Energy Storage." In *Proceedings of the 2005 International Conference on Future Power Systems*. November 18, 2005, Amsterdam, The Netherlands. Institute of Electrical and Electronics Engineers, Piscataway, New Jersey. Accessed October 22, 2010 at http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=1600538 (undated webpage).

[170] Driesen and Belmans 2006.

[171] LeMaire X. 2007. "Regulation and Distributed Generation." Presented at the ERRA Integration Workshop. July 6, 2007, Budapest, Hungary. Accessed July 12, 2010 at www.un.org/esa/sustdev/csd/csd15/lc/reep_regulation.pdf (undated webpage).

### A.7.5 Metric Recommendations

No data were found on the kWh of grid-connected distributed generation. The value may not currently be available, but should become so with more advanced metering. In addition, the EIA electric power production information could be improved with an indication of the portion of power production that is dispatchable as opposed to variable resources.

# A.8 Metric #8: Market Penetration of Electric Vehicles and Plug-In Hybrid Electric Vehicles

## A.8.1 Introduction and Background

This metric examines the penetration of electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) into the light-duty vehicle market. Light-duty vehicles include automobiles, vans, pickups, and sport utility vehicles (SUVs) with a gross vehicle weight rating of 8,500 pounds or less.[172] Electric vehicles are powered exclusively by electric drivetrains. A PHEV is a hybrid electric vehicle with batteries that can be recharged when plugged into an electric outlet and an internal combustion engine that can be activated when batteries require recharging.

The DOE encourages EV development through investments outlined in the American Recovery and Reinvestment Act (ARRA) and DOE's Advanced Technology Vehicle Manufacturing (ATVM) Loan Program. Together, these programs are supporting the "…development, manufacturing, and deployment of the batteries, components, vehicles, and chargers necessary to put million of EVs on America's roads."[173] The Recovery Act includes a $2.4 billion program designed to establish 30 manufacturing facilities for electric vehicle batteries and components. The scaling up of battery production to meet demand generated through PHEV sales could serve as an opportunity to reduce the cost per kilowatt of lithium ion batteries and provide a new source of batteries in a secondary application to the grid. For each dollar of federal funds invested in the program, private partners are investing at least one dollar. DOE's Advanced Research Projects Agency-Energy (ARPA-E) is providing an additional $80 million to transformative research and development projects designed to advance battery- and electric-drive component technology beyond current frontiers. The ATVM Loan Program to date has provided nearly $2.6 billion to Nissan, Tesla, and Fisker to establish EV manufacturing plants in Tennessee, California, and Delaware, respectively. These investments in EV battery, component, and manufacturing technologies are designed to achieve a number of objectives:

- lower the cost of some EV batteries by 70 percent by 2015
- enable U.S. manufacturers to produce a sufficient number of batteries and components to support the annual production of 500,000 electric-drive vehicles by 2015

[172] The definition of light-duty vehicles includes motorcycles. Although electric motorcycles are commercially available, plug-in hybrid motorcycles are unlikely to be pursued as a product. Therefore, we omitted motorcycles from this analysis.

[173] DOE – U.S. Department of Energy. 2010. *The Recovery Act: Transforming America's Transportation Sector – Batteries and Electric Vehicles*. U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://www.whitehouse.gov/files/documents/Battery-and-Electric-Vehicle-Report-FINAL.pdf (undated webpage).

- boost the production capacity of U.S. manufacturers to 20 percent of the world's advanced vehicle battery supply by 2012 and 40 percent by 2015.

The DOE encourages the development of PHEVs in the U.S. marketplace through its Vehicle Technologies Program. The DOE supports research into advanced vehicles and fuels, hybrid and EV systems, energy storage, and materials technology. The DOE supports the FreedomCAR and Fuel Partnership with the goal of developing emission- and petroleum-free cars and light trucks and supporting infrastructure. Toward the development of PHEVs, the DOE has established several long-term goals designed to make PHEVs cost-competitive by 2014 and ready for commercialization for volume production by 2016:[174]

- $3,400 marginal cost of PHEV technology over existing hybrid technology
- 40-mile all-electric range
- 100 miles per gallon equivalent
- PHEV batteries that meet industry standards regarding economic life and safety.

The smart grid supports EV and PHEV deployment through real-time pricing structures, bi-directional metering and vehicle-to-grid applications. Real-time pricing would enable customers to recharge vehicles during off-peak hours at reduced cost. Bi-directional metering would enable customers to purchase energy at off-peak hours and sell unused, stored energy back to the electricity service provider during peak periods at higher rates. These two elements could feasibly enhance the customer's return on investment (ROI) for EV and PHEV technologies and accelerate market penetration.

### A.8.2 Description of Metric and Measurable Elements

*(Metric 8) The total number and percentage shares of on-road light-duty vehicles*— comprising EVs and PHEVs. It also measures EV and PHEV penetration of the light-duty vehicle market, expressed as a percentage of new vehicle sales.

### A.8.3 Deployment Trends and Projections

Table A.8 presents estimates of EVs and PHEVs currently in use and projected out to 2030 based on the EIA's Annual Energy Outlook (AEO) 2010. This outlook, which is considered the AEO's reference case, is very conservative and does not consider potential future tax credits or

[174] FreedomCAR and Vehicle Technologies Program. 2007. *Plug-In Hybrid Electric Vehicle R&D Plan, Working Draft*. FreedomCAR and Vehicle Technologies Program, U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://search.nrel.gov/cs.html?url=http%3A//www1.eere.energy.gov/vehiclesandfuels/pdfs/program/phev_rd_plan_june_2007.pdf&charset=utf-8&qt=url%3Aeere.energy.gov/vehiclesandfuels/+%7C%7C+plug-in+hybrid+electric+vehicle&col=eren&n=2&la=en (last updated June 25, 2007).

other incentives. Other, more aggressive scenarios consider high economic growth and accelerated growth in oil prices.

Based on EIA data, the number of EVs operating on-road reached 26,823 in 2008, representing roughly 0.01 percent of all light-duty vehicles in use. EV sales were small in 2008, representing less than one-tenth of one percent of the light-duty-vehicle market share.[175] Customer acceptance of the EV will be put to the test with the newly introduced Nissan Leaf and its 100-mile all-electric range. The Nissan Leaf has a manufacturer's suggested retail price (MSRP) of as low as $32,780, or $25,280 after netting out all federal tax credits. Tesla offers a premium sports car version of the EV called the Roadster, which is commercially available at an MSRP of as low as $109,000, or $101,500 after federal tax credits.

The DOE does not estimate current PHEV sales, though Chevrolet recently introduced the 2011 Volt, which is a PHEV with an all-electric range of 40 miles. The Chevrolet Volt is offered at an MSRP of as low as $41,000, or $33,500 after federal tax credits. In addition, there are several companies that perform aftermarket PHEV conversions, including Amberjac Systems, Hybrids Plus, Plug-In Conversions Corp, and Hymotion. PHEV sales are forecast by DOE to reach 142,358 (0.9 percent of light-duty vehicle sales) by 2020 and 408,498 (2.3 percent of light-duty vehicle sales) by 2030.

As shown, the number of light-duty EVs in use is forecast to decline in future years to 4,177 by 2030; the decline in EVs in use does not reflect a trend away from alternative vehicle technologies, but rather a transition toward more competition among alternative technologies, some of which have not yet entered the marketplace. The PHEV share of on-road light-duty vehicles is forecast by DOE to grow slowly through 2030, reaching 3.3 million (1.2 percent of all light-duty vehicles).[176]

**Table A.8**. EV and PHEV Market Penetration[177]

| | EVs On-Road | | PHEVs On-Road | | EV Sales | | PHEV Sales | |
|---|---|---|---|---|---|---|---|---|
| Year | Total in Use | % of Light-Duty Vehicles | Total in Use | % of Light-Duty Vehicles | Total Sales | % of Light-Duty Market | Total Sales | % of Light-Duty Vehicles |
| 2008 | 26,823 | 0.01% | - | 0.00% | 120 | 0.00% | - | 0.00% |
| 2010 | 24,168 | 0.01% | - | 0.00% | 96 | 0.00% | - | 0.00% |
| 2015 | 17,738 | 0.01% | 243,859 | 0.10% | 146 | 0.00% | 89,173 | 0.54% |
| 2020 | 11,360 | 0.00% | 778,287 | 0.31% | 147 | 0.00% | 142,358 | 0.86% |
| 2025 | 6,663 | 0.00% | 1,749,761 | 0.65% | 151 | 0.00% | 276,325 | 1.63% |
| 2030 | 4,177 | 0.00% | 3,311,329 | 1.17% | 159 | 0.00% | 408,498 | 2.27% |

[175] EIA – Energy Information Administration. 2010. *Annual Energy Outlook 2010.* Supplemental Tables 57 (Total United States) and 58 (Light-Duty Vehicle Stock by Technology Type). DOE/EIA-0383(2010), Energy Information Administration, Washington, D.C. Accessed October 22, 2010 at http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html (last updated May 11, 2010).
[176] DOE 2010.
[177] DOE 2010.

The DOE forecast presented in the 2010 AEO is conservative compared to a number of recent forecasts prepared by industry. While some forecasts estimate ultimate hybrid electric and EV penetration of the light-duty vehicle market in the 8 to 16 percent range,[178] the EPRI and Natural Resources Defense Council (NRDC) were more aggressive, estimating PHEV market penetration rates under three scenarios, ranging from 20 to 80 percent (medium PHEV scenario estimate of 62 percent) in 2050. EPRI and NRDC used a consumer-choice model to estimate market penetration rates.[179]

The findings of the EPRI and NRDC study, as well as those for several other EV and PHEV market penetration studies, are presented in Figure A.16. Note that there are multiple estimates from several studies, representing forecast penetration rates at various future points in time. Further, some of the studies presented a range of estimates for single points in time based on various policy or technology assumptions; these studies are designated through high-low points connected with lines in the graph.

The report identified as "PNNL" in Figure A.16 was prepared for DOE by the Pacific Northwest National Laboratory (PNNL) in 2008. The report presented and examined a series of PHEV market-penetration scenarios given varying sets of assumptions governing PHEV market potential. Based on input received from technical experts and industry representatives contacted for the report and data obtained through a literature review, annual market penetration rates for PHEVs were forecast from 2013 through 2045 for three scenarios. Figure A.16 presents the results of the R&D Goals Achieved scenario. Under this scenario, PHEV market penetration was forecast to ultimately reach 30 percent, with 9.9 percent achieved by 2023 and 27.8 percent reached by 2035.[180]

[178] Greene D, K Duleep, and W McManus. 2004. *Future Potential of Hybrid and Diesel Powertrains in the U.S. Light-Duty Vehicle Market.* ORNL/TM-2004/181. Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed November 24, 2008 at http://www.ornl.gov/~webworks/cppr/y2004/rpt/121097.pdf

[179] EPRI – Electric Power Research Institute, National Resources Defense Council (NRDC), and Charles Clark Group. 2007. *Environmental Assessment of Plug-in Hybrid Electric Vehicles – Volume 1: Nationwide Greenhouse Gas Emissions.* Electric Power Research Institute, Palo Alto, California. Accessed November 24, 2008 at http://mydocs.epri.com/docs/public/000000000001015325.pdf (undated webpage).

[180] Balducci PJ. 2008. *Plug-In Hybrid Electric Vehicle Market Penetration Scenarios.* PNNL-17441. Prepared by Pacific Northwest National Laboratory for the U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17441.pdf (undated webpage).

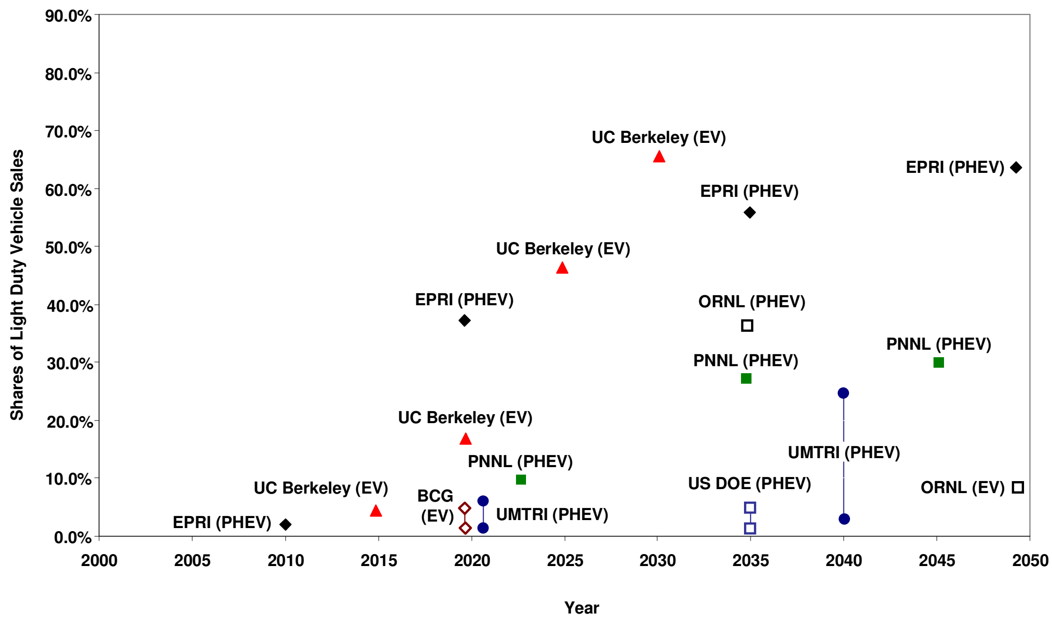


**Figure A.16**. PHEV Market Penetration Scenarios

The report prepared by the University of Michigan Transportation Research Institute (UMTRI) relied on an agent-based model that simulated the automotive marketplace through interactions between automotive consumers, fuel producers, vehicle producers/suppliers, and government agencies. The interactions between these four classes of decision makers were modeled based on individual objectives and needs. The agent-based model designed for this study estimated PHEV market penetration rates of 1 to 3 percent (fleet penetration of approximately 1 percent) by 2015, 1 to 5 percent (fleet penetration of 1 to 3 percent) by 2020, and 1 to 25 percent (fleet penetration of 1 to 20 percent) by 2030. The scenarios presented in the UMTRI report are differentiated based on assumptions regarding original equipment manufacturer (OEM) subsidies and sales tax exemptions. As OEM subsidies and sales tax exemptions are applied, the agent-based model estimates larger market shares for PHEVs.[181]

A recent report prepared by Greene and Lin (2010) at the Oak Ridge National Laboratory (ORNL) used a consumer-choice model to estimate the market penetration of competing alternative technologies under two scenarios: a) a base case that maintains the current policy environment calibrated to the 2009 AEO Updated Reference Case, and b) a case that assumes that the goals of the DOE FreedomCAR program are achieved. Under the base-case scenario, PHEV sales reach 1 million (5.1 percent of light duty vehicle sales) by 2037 and 3 million (12.5 percent of light duty vehicle sales) by 2050. Under the FreedomCAR Goals case, PHEV sales would grow more rapidly, reaching 1 million (6.0 percent of light-duty vehicle sales) by

[181] Sullivan JL, IT Salmeen, and CP Simon. 2009. *PHEV Marketplace Penetration: An Agent Based Simulation.* UMTRI-2009-32. Prepared by the University of Michigan Transportation Research Institute for the U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://hdl.handle.net/2027.42/63507 (undated webpage).

2020 and 7 million (36.9 percent of light-duty vehicle sales) by 2050. Also, EV sales reach 2 million, or 8.3 percent of light duty vehicle sales, in 2050 under the FreedomCAR Goals case.[182] The findings of the FreedomCAR Goals Case are presented in Figure A.16 labeled as ORNL.

The study prepared by Becker and Sidhu of the University of California, Berkeley's Center for Entrepreneurship and Technology adapted the Bass model, which has been used to forecast market penetration for other new technologies, to an EV with switchable batteries, which, when discharged, can be replaced with a charged battery rather than stopping to recharge. The market for an EV with switchable batteries was established using survey data on U.S. driving patterns given differing assumptions regarding oil prices. The adapted Bass model was then used to estimate technology adoption rates. Based on the survey data underpinning the analysis and the increasingly aggressive oil price assumptions, Becker and Sidhu (2009) estimate market penetration rates for the EV with switchable batteries of 64 to 85 percent by 2030. The low-end estimate relies on oil price data presented in the EIA AEO's reference case, while higher-end estimates use the EIA high oil price case and assume operator subsidies.[183]

In addition to the aforementioned studies, Figure A.16 presents the findings of the Boston Consulting Group's study of EV penetration, which estimated market penetration of 1 to 5 percent in the U.S. by 2020. Additionally, the range of penetration rates for PHEVs presented in EIA's 2010 AEO was 1.7 to 3.9 percent in 2035, with the difference accounting for varying assumptions regarding oil prices.[184]

The forecasts in Balducci (2008), Sullivan et al. (2009), and EPRI/NRDC (2007) were designed with scenarios based on increasingly aggressive assumptions. Some of these scenarios assume that the PHEV will ultimately become the dominant alternative fuel vehicle. The EPRI/NRDC study was focused on the potential environmental impact of PHEV market penetration. Therefore, aggressive assumptions were required under some of the scenarios to generate a reasonably significant and measurable environmental impact. These studies do not present the scenarios as definitive or assign probabilities to their outcomes. Rather, the studies are designed to measure the effect or estimate the penetration rate, given certain sets of assumptions. If the goals outlined in Balducci (2008) are not reached, market penetration rates would certainly be lower than estimated. DOE estimates are generated by the National Energy Modeling System (NEMS), which does not use aggressive assumptions to determine the market

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[182] Greene D and Z Lin. 2010. "A Plug-in Hybrid Consumer Choice Model with Detailed Market Segmentation." In *Proceedings of the Transportation Research Board 89th Annual Meeting*. January 10-14, 2010, Washington, D.C.

[183] Becker T and I Sidhu. 2009. *Electric Vehicles in the United States: A New Model with Forecasts to 2030*. 2009.1.v.2.0, Center for Entrepreneurship and Technology, University of California, Berkeley. Accessed October 22, 2010 at http://cet.berkeley.edu/dl/CET_Technical%20Brief_EconomicModel2030_f.pdf (undated webpage).

[184] DOE 2010.

potential of PHEVs. Instead, the light-duty alternative-fuel vehicle market is forecast by NEMS to be dominated by diesel, flex-fuel, and hybrid electric vehicles, not PHEVs.

#### A.8.3.1 Associated Stakeholders

To date, virtually all EVs have been marketed to public agencies and private companies. Thus, sales to private citizens have been historically low. In 2006, 94.7 percent of all EVs in use were owned by private companies and municipal governments.[185] An additional 4.1 percent were owned and operated by state agencies. The remaining 1.2 percent were operated by federal agencies, electric utilities, natural gas companies, and transit agencies.[186]

In addition to the fleet operators identified above, stakeholders in the EV and PHEV market space include

- end users – Those who own EVs need straightforward and safe ways to charge their vehicles and be provided with incentives and technology that encourage off-peak charging so that distribution and system-capacity constraints are accommodated.
- electric-service retailers – This group needs to provide consumers with reasonable programs for accommodating EVs. They need to coordinate the constraints on the generation and delivery of electricity and have incentives from the delivery and wholesale-power stakeholders to enhance the efficient use of electric resources. Metering and communication mechanisms need to be deployed to meet the needs of the energy products offered.
- distribution-service providers – The planning and operations of the distribution system need to manage the peaks in EV consumption so capacity constraints are not violated. More distribution system assets will be needed, but encouraging higher asset utilization with greater use of off-peak capacity can mitigate potential electricity rate increases.
- transmission providers – As EV penetration increases, the bulk power grid may potentially need some investment as well. Unlike the distribution system, the load impacts from EVs and PHEVs are more diversified and with load control strategies should not contribute significantly toward the system peak.
- balancing authorities – Charging systems developed with the ability to schedule and respond to emergency system situations can provide new, fast-acting resources to system operators. The demand side, with high penetrations of EVs, can provide system reserve and balancing resources if equipped with communications and control technologies.

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[185] EIA – Energy Information Administration. 2010. “Estimated Number of Electric Vehicles in Use, by State and User Group, 2008.” *Alternatives to Traditional Transportation Fuels 2008,* p. 26. Energy Information Administration, Washington, D.C. (undated webpage).
[186] DOE 2010b.

- generation and demand wholesale market operators – EVs whose charging can be scheduled and respond to grid conditions can be aggregated at the wholesale level to provide competition with other generation and demand resources. Market trading products need to be reviewed as penetration levels become significant. The estimation of the resource availability is challenging because of the uncertainties of the resource mobility.
- automotive manufacturers – Automotive manufactures have increasingly acknowledged the market feasibility of EVs and PHEVs as evidenced by the recently announced introduction of the Nissan Leaf and Chevrolet Volt. Federal OEM subsidies and tax incentives have encouraged the development of EVs and PHEVs by improving the value proposition and ROI on electric-drive vehicle purchases.
- products and services suppliers – This represents a new market area for suppliers. Battery manufacturers, home energy management systems, electric battery charging station manufacturers, advanced-meter manufacturers, and auto manufacturers are just some of the stakeholders who will look to develop business plans in this area.
- policymakers and advocates – Policy decisions are needed for funding EV and PHEV research and development programs and tax incentives, and establishing the regulatory framework in which the other stakeholders operate. System reliability and cyber-security issues become heightened concerns as greater penetration levels are realized. Policy advocates would also include environmental groups focused on reducing emissions through enhanced EV and PHEV adoption.
- standards organizations – A community of stakeholders from the automotive, power, electrical, mechanical, and software engineering communities needs to coordinate to initiate work on standards that will support the physical and information networking integration of EVs with the electricity system. Building code regulatory authorities are working toward a national model code for municipalities and other regional and local regulatory authorities to adopt building codes to make future single and multi-family dwellings EV/PHEV ready.
- financial community – Venture capital and investment firms will be important players for providing the capital to fund entrepreneurial and regulated electricity service provider infrastructure efforts needed to support growth in this area.

#### A.8.3.2 Regional Influences

In 2008, the five states with the greatest number of EVs operating on-road were California (53.1 percent), New York (14.2 percent), Arizona (6.7 percent), Massachusetts (4.4 percent), and Michigan (3.4 percent). In 2008, roughly 53.1 percent of all EVs in use were operated in California, reflecting the state's commitment to improving air quality through the adoption of a number of standards and programs, such as the Zero Emission Vehicle Program, designed to reduce vehicle emissions.

Regional differences in market penetration depend largely on state policies that affect the cost of owning and operating EVs. Figure A.17 presents a map of state incentives either proposed or in place. As shown, incentives are either planned or provided throughout the western United States and Northeast. For example, Arizona lowers licensing fees for EVs, and California offers rebates of up to $5,000 for battery electric vehicles (BEVs), $3,000 for PHEVs, and $1,500 for electric motorcycles. Oregon recently put $5,000 tax credits in place to offset conversion or purchase costs for PHEVs, and allows $1,500 tax credits for BEVs. These incentives are in addition to federal tax credits of $2,500 to $7,500 for EVs and PHEVs depending on battery size.

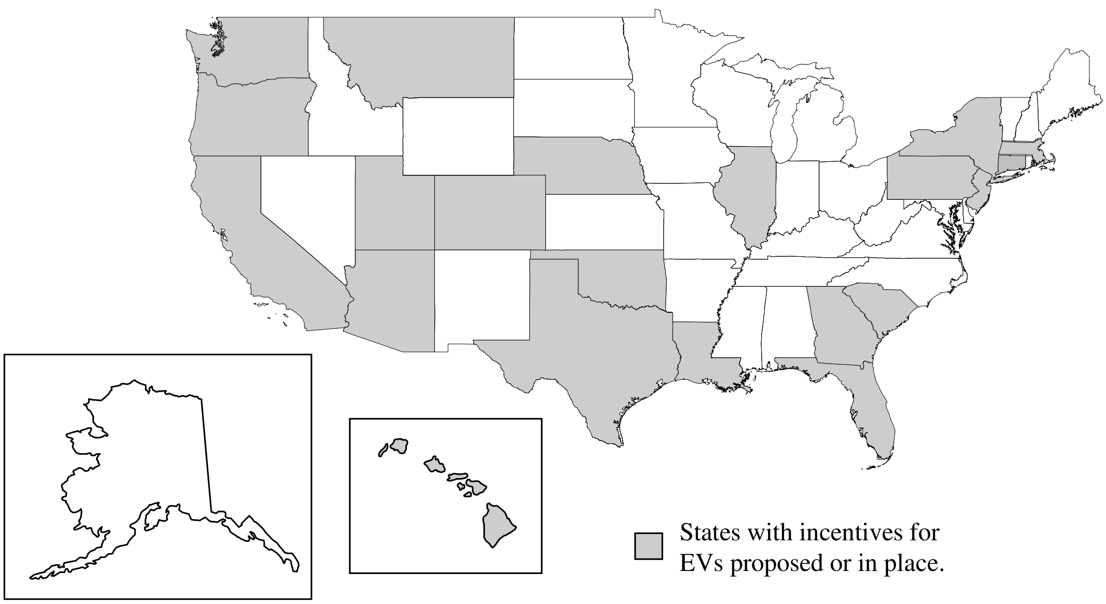


**Figure A.17**. State Incentives for Electric Vehicles

The market success of EVs and PHEVs is also influenced by regional differences in the prices of electricity and motor fuel. As retail prices for electricity increase relative to the price of gasoline, demand for EVs and PHEVs would be expected to decline. The retail price per kilowatt-hour by state can be reviewed at the DOE's EIA website, at http://www.eia.doe.gov/fuelelectric.html.

The availability of idle electric capacity is also a regional issue. A study conducted for DOE found that electric infrastructure in the U.S. could support the conversion of up to 73 percent of the light-duty-vehicle fleet to PHEVs without adding more generation and transmission capacity. This figure represents the technical potential and would require strategies for perfect valley-filling of the daily load profile. The availability of electricity in off-peak periods differed by region, with less power available in the Northwest Power Pool Area (10 percent) and California and southern Nevada Area (15 percent), and more power available in the Electric Reliability Council of Texas Area (100 percent), Mid-Continent Area Power Pool Area (105 percent), Southwest Power Pool Area (127 percent), and the area covered by the East Central Area Reliability Coordinating Agreement (104 percent).[187]

### A.8.4 Challenges to Deployment

Market penetration generally follows along a logistic-function, or s-shaped, curve. The market-penetration curve would include a period leading up to the introduction of commercially viable EVs and PHEVs; early stages of commercialization, with an evolving technology and new battery and automotive manufacturing facilities being brought on line; ramp-up of production with a mature technology and a significant expansion in the capacity to manufacture and distribute EVs and PHEVs; and finally, full market potential being reached within relevant market constraints. At each stage in the development process there will be technical and financial barriers that must be addressed. These barriers are discussed below.

#### A.8.4.1 Technical Challenges

Technical barriers include those related to battery technologies; the automotive manufacturing process; supply-chain, refueling and range limitations; and electricity-infrastructure capacity:

- Battery technology limitations include energy intensity, durability, battery life, battery safety aspects, intellectual property (IP) issues, battery size and weight, the cost to manufacture the batteries required to power EVs and PHEVs, and raw-material constraints.
- Automotive manufacturing process limitations include incorporation of the weight and space demands of the battery systems; design of instruments to monitor the charge and temperature of the battery system; incorporation of blowers, pumps and other elements into the design process; building of the battery system into the manufacturing process; re-tooling of plants; and maintenance of vehicle safety.
- Supply chains will need to evolve in order to build suppliers of everything from power transistors to high-density circuit boards. Battery-recycling industry and processes need to be developed. Battery-testing facilities will also need to be expanded to test new battery systems.

[187] Kintner-Meyer M, K Schneider, and R Pratt. 2007. "Impacts Assessment of Plug-In Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids, Part I: Technical Analysis." In *Electric Utilities Environmental Conference, the 10th Annual EUEC Conference and Expo. Clean Air, Mercury, Global Warming and Renewable Energy*, Vol. 1. January 22-24, 2007, Tucson, Arizona.

- The limited ability to refuel while traveling and significant limitations in the range of all-electric vehicles limit market penetration. While this challenge continues today, EV charging stations are being installed across the U.S. and, by 2015, Pike Research estimates that nearly 1 million charging stations will be in place in the U.S. with 4.7 million available worldwide.[188] In comparison, there were approximately 159,000 retail gasoline outlets located in the U.S. in 2010.[189]
- Approximately one-third of all light-duty vehicles park in the street with very limited or no access to a 120-V or 240-V power supply. Infrastructure would need to be developed to provide access to recharging outlets for those customers who live in high-density apartment and condominium complexes.
- Charging controls will be necessary to minimize the impact of EVs and PHEVs on electricity service providers. Off-peak (nighttime) charging will minimize the need for equipment upgrades on the electrical distribution system. Recent research on the impacts of Level 1 (120V) and Level 2 (240V) charging on the electricity delivery system points to the potential for overloading distribution transformers, fuses, switches, and regulators on distribution feeders depending on the density of early adopters of EVs and PHEVs, particularly when a high concentration of Level 2 charging is expected.[190,191] In response to this concern, electricity service providers in California (e.g., City of Palo Alto Utilities and Burbank Water and Power) are working to identify where EVs and PHEVs are likely to first appear in order to plan for the increased demand in a manner that will reduce the possibility of an early setback in the effort to enhance EV and PHEV penetration and reduce petroleum consumption.

#### A.8.4.2 Business and Financial Challenges

Financial and customer-perception barriers include the following:

- The top consumer concerns about hybrid electric vehicles are insufficient power (34 percent), price (27 percent), and vehicle dependability (24 percent).[192] These concerns would transfer to the EV and PHEV marketplace.

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[188] Pike Research. 2010. *Electric Vehicle Charging Equipment.* Pike Research, Boulder, Colorado.
[189] National Petroleum News. 2010. *NPN Magazine July/August 2010 Issue.* Park Ridge, IL.
[190] Gerkensmeyer C, MCW Kintner-Meyer, and JG DeSteese. 2010. *Technical Challenges of Plug-In Hybrid Electric Vehicles and Impacts to the US Power System: Distribution System Analysis.* PNNL-19165, Pacific Northwest National Laboratory, Richland, Washington. Accessed January 10, 2011 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-19165.pdf (undated webpage).
[191] Onar O and A Khaligh. 2010. "Grid Interactions and Stability Analysis of Distribution Power Network with High Penetration of Plug-In Hybrid Electric Vehicles." In *Proceedings of the Twenty-Fifth Annual IEEE Applied Power Electronics Conference and Exposition (APEC)*. February 21-25, 2010, Palm Springs, California. Accessed January 10, 2011 at http://ieeexplore.ieee.org/iel5/5426413/5433335/05433471.pdf?arnumber=5433471 (undated webpage).
[192] Greene et al. 2004.

- There are driver profiles that do not favor EVs and PHEVs (e.g., heavy use on highways, long commutes, transport of heavy loads).

Consumers generally require short payback periods and the current cost to convert a hybrid electric vehicle to a PHEV and the marginal cost associated with EV or PHEV technology would result in a payback period that is unacceptable to most customers.

### A.8.5 Metric Recommendations

Because PHEVs are receiving increasing attention among industry experts, alternative forecasts of PHEV market penetration have been presented from several sources. These forecasts, however, vary significantly in their underlying assumptions, methods, and findings. As additional studies are completed and PHEVs are introduced into the marketplace, these forecasts should become more unified. These studies should be identified and compared against what appear to be conservative forecasts built into the U.S. Department of Energy's *Annual Energy Outlook*. Some analysis of these alternative forecasts should be performed in order to determine the most likely market penetration trajectory.

# A.9 Metric #9: Grid-Responsive, Non-Generating Demand-Side Equipment

## A.9.1 Introduction and Background

This metric measures the penetration of demand-side equipment that is responsive to the dynamic needs of the smart grid. The products that have emerged and continue to evolve in this category either directly monitor or receive communicated recommendations from the smart grid. This equipment then provides the useful dynamic responses to those needs either through automated responses or through the conveyance of useful information to consumers who then might appropriately respond. This metric includes only those grid-responsive features that are available on original equipment or by the simple retrofit of existing equipment without needing highly skilled labor. This metric intentionally excludes advanced meters (addressed in Metric 12), communications gateways (e.g., home management systems, building automation systems), equipment that generates or stores electrical energy, and equipment that requires unique engineering for its installation at an endpoint. This excludes much industrial and commercial equipment, except those examples having dynamic grid responses that are supplied on original equipment or by simple retrofit. The metric excludes many "smart" equipment features that target conservation (e.g., occupancy sensors, dirt sensors) or non-energy purposes (e.g., entertainment, security, health).

Examples of grid responsive equipment include communicating thermostats, responsive appliances, responsive heating, ventilation and air conditioning (HVAC) equipment, consumer energy monitors, responsive lighting controls, and controllable wall switches. This category of equipment also encompasses switches, controllable power outlets, and various other controllers that could be used to retrofit or otherwise enable existing equipment to respond to smart grid conditions. For example, a new "smart" refrigerator may be equipped with a device that coordinates with the facility's energy management system to adjust temperature controls, within user-specified limits, based on energy prices. Perhaps a new "smart" surge protector or power strip would communicate with the facility's energy-management system on behalf of the appliances plugged into it. An energy "orb" or indicator in a laundry room could advise owners of energy price penalties and opportunities. Consumers whose equipment connects to the internet might remotely receive equipment status updates and energy price updates, and be informed of maintenance issues by email or another message service. These devices may also have device settings remotely controlled over the internet. The examples are numerous and more will be invented.

The technology exists to implement such grid-responsive equipment; however, there is little standardized supporting infrastructure to communicate with the equipment, nor is there significant demand for it yet, since only approximately eight percent of U.S. energy customers now have any form of time-based or incentive-based price structure.[193]

### A.9.2 Description of Metric and Measurable Elements

This metric tracks the effectiveness and penetration of grid-responsive, non-generating demand-side equipment. The distinction from Metric 5 is that this metric focuses on the original equipment that is equipped to be more responsive to load, while Metric 5 addresses benefits achieved from all controllable loads. The following two measurements have been identified as important to understanding and quantifying grid-responsive, non-generating demand-side equipment.

*(Metric 9.a) Total U.S. load capacity in each consumer category (i.e., residential, commercial, and industrial) that is actually or potentially modified by behaviors of smart, grid-responsive equipment (MW)*—tracking the influence of new and enhanced "smart" consumer equipment differentiated between residential, commercial, and industrial types defines this metric.

*(Metric 9.b) Total yearly U.S. retail sales volume for purchases of smart, grid-responsive equipment ($)*—establishing an overall market-share baseline for these devices will allow analysts to chart device penetration and commercialization success.

### A.9.3 Deployment Trends and Projections

FERC's 2009 *Assessment of Demand Response and Advanced Metering*[194] estimated about 37 GW of available demand response in the U.S. Only about 8 percent of customers were on some form of rate- or incentive-based demand-response program. FERC's assessment further breaks this attribution out by region and by customer type. While useful, these numbers are not directly comparable to the numbers of those proposed for this metric. First, the smart equipment we wish to track could offer features other than traditional demand response. For example, a price-alert signal on a dryer would probably qualify the equipment as smart and responsive to the needs of the grid, but it does not necessarily bring about direct demand response. However, this metric is not exclusively focused on automated grid response, and additionally includes equipment that is directly operated by consumers. FERC estimates also include scheduled voluntary responses (especially for industrial programs) that are communicated by phone or email and do not necessarily use or require any automation and smart equipment.

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[193] FERC – Federal Energy Regulatory Commission. 2008. *Assessment of Demand Response and Advanced Metering.* Staff Report, December 2008. Federal Energy Regulatory Commission, Washington, D.C. Accessed November 6, 2008 at http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf (undated webpage).

[194] FERC – Federal Energy Regulatory Commission. 2009. *Assessment of Demand Response and Advanced Metering.* Staff Report, September 2009. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/sep-09-demand-response.pdf (undated webpage).

Programmable, communicating thermostats are a near-term success in this equipment category. Numerous installations of communicating thermostats have been conducted at pilot scale, and full-implementation installations are being launched. The California Energy Commission planned to require programmable communicating thermostats as part of its 2008 Update to the Building Energy Efficiency Standards, but revised this requirement.[195] A recent report prepared for the California Energy Commission notes that 69 percent of California residents have programmable thermostats, with 36 percent of those capable of two-way communication.[196] Based on EIA electricity customer data, that amounts to approximately 3.7 million electricity customers in California with communicating thermostats in 2009. Austin Energy is also presently evaluating the performance of 70,000 installed smart thermostats as part of its broader "Pecan Street Project."[197]

Smart, grid-responsive appliances remain in their commercialization infancy. Trials have occurred in small pilot-scale installations, where, in most cases, only limited integration of the grid-responsive features has been achieved. For example, the DOE ran a smart-grid experiment on the Olympic Peninsula, Washington, where they tested retrofitted thermostats, water heaters, and clothes dryers fitted with communicating, grid-responsive equipment in 112 homes.[198] The results were promising. The equipment reduced load fluctuations and decreased peak loads and consumer energy costs.[199] As of 2002, through the use of gateway technology pioneered by Salton, Inc. and Microsoft, Westinghouse has manufactured appliances such as bread machines and coffee makers that communicate with each other through an alarm-clock-like gateway that synchronizes its schedule and those of all its communication-enabled devices via the internet.[200] Conceivably, these communicating appliances could respond to energy objectives, although they are promoted for consumer

[195] CEC – California Energy Commission. 2008. *California's Energy Efficiency Standards for Residential and Nonresidential Buildings.* Accessed July 20, 2010 at http://www.energy.ca.gov/title24/ (last updated January 1, 2010).

[196] Palmgren C, N Stevens, M Goldberg, R Barnes, and K Rothkin. 2010. *2009 California Residential Appliance Saturation Study*. CEC-200-2010-004-ES. Prepared for the California Energy Commission by KEMA, Inc. Accessed November 1, 2010 at http://www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF (undated webpage).

[197] FERC 2009.

[198] Lightner E. 2010. "How Smart Grid can Enable Electricity to be the Fuel of the Future." Presented at SAE 2010 Government/Industry Meeting. January 26-29, 2010, Washington, D.C. Accessed October 22, 2010 at http://www.sae.org/events/gim/presentations/2010/EricLightner.pdf (undated webpage).

[199] Hammerstrom DJ, R Ambrosio, J Brous, TA Carlon, DP Chassin, JG DeSteese, RT Guttromson, GR Horst, OM Jarvegren, R Kajfasz, S Katipamula, L Kiesling, NT Le, P Michie, TV Oliver, RG Pratt, S Thompson, and M Yao. 2007. *Pacific Northwest GridWise™ Testbed Demonstration Projects: Part I. Olympic Peninsula Project*. PNNL-17167. Prepared by Pacific Northwest National Laboratory for the U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://gridwise.pnl.gov/docs/op_project_final_report_pnnl17167.pdf (undated webpage).

[200] *Business Wire*. April 22, 2002. "Salton, Inc. Introduces 'Smart' Home Appliances Under the Westinghouse Brand Powered by Microsoft." Accessed July 20, 2010 at http://www.allbusiness.com/food-beverage/food-beverage-overview/5933350-1.html (last updated April 22, 2002).

convenience and other non-energy objectives. Other manufacturers are also developing and testing responsive appliances.

Retrofittable lighting controls have existed for years. Lighting can already be controlled at smart, communicating circuit panels.[201] Wirelessly addressable and dimmable fluorescent fixtures have become available for daylight adjustments and for commercial-building demand response.[202,203]

Autonomously responding equipment is also in its infancy, though more manufacturers are exploring smart-grid responsive designs. General Electric (GE) introduced their first "smart" water heaters, while smart-grid responsive models of other appliances remain in electricity service provider demonstration projects. Zpryme Research and Consulting projects that the U.S. smart appliance market will expand from $1.42 billion in 2011 to $5.46 billion in 2015, representing a nearly 40 percent growth rate. Clothes washers and dryers are expected to make up 36 percent of the market while refrigerators and freezers are forecast to comprise 24 percent of the market. Whirlpool expects to make all appliances smart grid capable by 2015.[204]

Some large commercial air handlers have been installed with under-frequency or under-voltage responses. Two hundred clothes dryers and water heaters were retrofitted with an autonomous under-frequency response during the Grid Friendly™ Appliance Demonstration.[205] Frequency responses have also been installed via load-control modules (not necessarily fitting our equipment category) and are being installed on refrigerators in the United Kingdom to provide dynamic demand.[206] By 2006, Hawaiian Electric Company, Inc. (HECO) had retrofitted 11,827 electric water heaters with Cooper Power System's Line Under-Frequency (LUF)

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[201] Emerson Climate Technologies. 2003. *Smart Appliances*. 026-1711 Rev 0 6-12-03, Computer Process Controls, Kenesaw, Georgia.

[202] Westinghouse. 2004. *RetroLUX™ T-5 Lighting System*. Westinghouse Lighting Corporation, Philadelphia, PA. Accessed July 20, 2010 at http://www.energysolve.com/Retrolux%20Sell%20Sheet.pdf (undated webpage).

[203] Piette MA, S Kiliccote, and G Ghatikar. 2008. "Linking Continuous Energy Management and Open Automated Demand Response." In *Proceedings of Grid-Interop Forum 2008*. November 11-13, 2008, Atlanta, Georgia. Accessed July 20, 2010 at http://openadr.lbl.gov/pdf/1361e.pdf (undated webpage).

[204] Zpryme Research and Consulting. 2010 "Smart Grid Insights: Smart Appliances. March 2010." Austin, TX.

[205] Hammerstrom DJ, J Brous, TA Carlon, DP Chassin, C Eustis, GR Horst, OM Järvegren, R Kajfasz, W Marek, P Michie, RL Munson, T Oliver, and RG Pratt. 2007. *Pacific Northwest GridWise™ Testbed Demonstration Projects: Part II. Grid Friendly™ Appliance Project.* PNNL-17079. Prepared by Pacific Northwest National Laboratory for the U.S. Department of Energy, Washington, D.C. Accessed November 18, 2008 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17079.pdf (undated webpage).

[206] Howe A. 2008. "Introducing Dynamic Demand." Presented at the Technology Track of the Grid-Interop Forum 2008. November 12-13, 2008, Atlanta, Georgia. Accessed October 22, 2010 at http://www.sessionview.com/data/2008/11/26/pdf/Andrew-Howe-3713.pdf (undated webpage).

controllers, representing 8.04 MW of under-frequency-responsive load.[207] On November 4, 2009, Reliant Energy and GE began a joint smart-appliance demonstration project in the homes of families of Reliant employees in Texas. The project's goal is to demonstrate how a typical family might make use of smart-grid connected washing machines, dryers, and refrigerators to manage their home energy use.[208] GE has also been working with Louisville Gas and Electric (LG&E) over the past year on a smart grid demonstration project in Louisville, Kentucky to test the interaction between smart appliances and smart meters under dynamic pricing conditions.[209]

Many residential and commercial aggregators already incorporate web-page information services to utilities and customers as part of their system. Ambient Devices' wireless energy orb was demonstrated in conjunction with PG&E; the orb color indicated to customers various dynamic electrical energy price conditions.[210] Whirlpool Corporation demonstrated in its Woodridge Study that appliance consumption could be reduced and deferred by appliance panel indicators and customer feedback.[211]

Due to their recent addition to the market, estimates of current smart and web-enabled equipment, as well as forecasts, are hard to obtain. However, due to the convenience, as well as the energy and cost-savings potential of these devices, demand for such devices is expected to increase as the supporting infrastructure becomes available. Even if consumer acceptance grew, however, electricity service providers often do not have system capabilities that would enable the benefits associated with these devices. According to recent interviews conducted for this report (Appendix B):

- Fifteen (62.5 percent) of the responding electricity service providers presently have no automated responses for signals sent to major energy-using equipment.
- Seven companies (29.2 percent) have some automated responses in development.

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[207] Block K, J Layer, and R Rognli. 2007. "Cooper Power Systems Cannon Demand Response Goes Hawaiian." *The Line*, August 2007. Cooper Power Systems. Accessed July 20, 2010 at http://www.cooperpower.com/Library/TheLine/pdf/07_08/Line_HECO.pdf (undated webpage).

[208] *Ordons News*. February 10, 2010. "Demand for GE's Smart Appliances Increases in Smart Grid Pilot Programs." Accessed October 8, 2010 at http://www.ordons.com/americas/north-america/2786-demand-for-ges-smart-appliances-increases-in-smart-grid-pilot-programs.html (last updated February 10, 2010).

[209] GE – General Electric. March 18, 2009. "GE Announces Program to Partner with Utilities to Reshape Energy Usage, Help Consumers Save Money." Press Release. Accessed October 8, 2010 at http://www.geconsumerproducts.com/pressroom/press_releases/company/company/GE_LGE_smartappliances.htm (undated webpage).

[210] Ambient Devices. Undated. *PG&E Demand-Response Orb*. Accessed July 20, 2010 at http://www.ambientdevices.com/cat/orb/PGE.html (undated webpage).

[211] Horst GR. 2006. *Whirlpool Corporation Woodridge Energy Study and Monitoring Pilot.* Whirlpool Corporation. Accessed July 20, 2010 at http://uc-ciee.org/dretd/documents/Woodridge%20Final%20Report.pdf (undated webpage).

- Two companies (8.3 percent) have a small amount, serving less than 10 percent of all customers, of automated responses in place.

#### A.9.3.1 Associated Stakeholders

Associated stakeholders include

- end users – Incentives to reduce electricity bills as peak-demand electricity prices rise.
- balancing authorities and reliability coordinators – Frequency-responsive devices can greatly benefit the grid during stressed conditions and prevent blackouts.
- product and service providers – They are interested, if there is a market. Appliance manufacturers will have an obvious role to play in providing the market with competitive and high-quality “smart” solutions and should welcome an opportunity to compete by providing better grid services than their competitors. Developers of wireless transmission platforms also have a large stake in determining a standard technology for transmitting data to grid-responsive devices.
- policymakers – Incentives to create a more reliable grid.

#### A.9.3.2 Regional Influences

These devices will be expected to meet the same standards that non-smart devices are required to meet in terms of energy use, safety, and other regional parameters.

The evolution of smart grid devices will be heavily influenced by the way energy programs are offered and enacted. Energy programs tend to be localized and regional; however, smart grid devices will be most economically manufactured for a larger national, or even global, customer set. Cost-effective application of smart grid devices will be difficult to attain without much standardization.

### A.9.4 Challenges to Deployment

Smart, grid-responsive equipment faces significant implementation challenges. As was succinctly stated by Arthur Rosenfeld, Commissioner, CEC, in a 2005 memorandum concerning programmable, communicating thermostat programs in California, “We perceive that the barriers to increased market penetration include relatively high costs of hardware installation, no plug-and-play capabilities, lack of a universal communication protocol to send price or emergency signals, and a lack of product availability at big box retailers.”[212]

[212] Rosenfeld A. 2005. *Memorandum to Demand Response Planning Meeting Attendees*. Accessed November 17, 2008 at http://www.title24dr.com/PDFs/Demand%20Response%20Memo.pdf

#### A.9.4.1 Technical Challenges

Among the biggest challenges facing these devices are technical considerations. Implementing communication interfaces in modern appliances requires significant investments in hard-, soft-, and firm-ware design.[213] Memory considerations such as the amount of data storage and networking options are an important concern. Other hardware considerations include accommodating diverse operating environments such as temperature and water exposure. Further decisions will have to be made regarding communications options. "Wired" networking options have costs and performance characteristics different from those of "wireless" networking options. Even between these two technologies, there is presently little guidance from standards regarding how grid-responsive appliances within the home interface with either each other or with control interfaces. Because wirelessly integrated appliances remain a nascent technology, the industry has yet to establish a default interfacing platform among the three leading standards—wifi, ZigBee, and Z-Wave.[214] Additionally, it will be necessary to increase the ability of either platform to transmit the volumes of data required for a machine or home network to be responsive to a smart grid.[215]

#### A.9.4.2 Business and Financial Challenges

Currently, there is significant interest in this field. Businesses such as LG Electronics and Westinghouse are designing and producing more "web-enabled" household appliances. Research and development in these fields will poise producers to easily transition into "smart" devices. However, incorporating electronics into increasing numbers of appliances, as well as developing and maintaining software for these appliances, will require a new look at the products' life-cycle costs. Manufacturers and grid entities have not yet settled on standards that would give manufacturers the confidence necessary to fully integrate and launch grid-responsive equipment. Perhaps this is because the business case for integration of these features has not yet been fully proven.

### A.9.5 Metric Recommendations

The smart equipment discussed in this metric remains in its infancy. New examples continue to emerge. Consequently, the definition of which equipment should and should not be counted in this metric can also be expected to evolve in the next few years. An issue in

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[213] Eckel C, G Gaderer, and T Sauter. 2003. "Implementation Requirements for Web-Enabled Appliances – a Case Study." In *Proceedings of the 2003 IEEE Conference on Emerging Technologies and Factory Automation Proceedings (ETFA 2003)*, Vol. 2, pp. 636-642. September 16-19, 2003, Lisbon, Portugal. Institute of Electrical and Electronics Engineers, Piscataway, New Jersey. Accessed July 20, 2010 at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=1248758 (undated webpage).

[214] Gabriel C. December 2, 2009. "Zigbee and Z-Wave in Smart Grid Stand-Off, with Wi-Fi the Wild Card." *4GTrends.com*. Accessed October 12, 2010 at http://4gtrends.com/?p=2329 (last updated December 2, 2009).

[215] Gabriel 2009.

defining this metric is the emphasis on residential appliances. Commercial-building and industrial equipment with embedded, grid-responsive capability deserves to be more closely scrutinized in future SGSRs.

Today, the number of responsive equipment of other types is overwhelmed by the relative commercial success of communicating thermostats. This metric might be more meaningful if it were separated from the rest, leaving a catch-all category for other grid-responsive equipment that is in a much less mature state of commercialization.

Secondary information sources were not readily found for estimating penetration of grid-responsive equipment. More effort is required to accurately quantify the penetration of responsive equipment. In two years, pilot installations of responsive equipment examples should be more readily available.

# A.10 Metric #10: Transmission and Distribution Reliability

## A.10.1 Introduction and Background

The purpose of this metric is to quantify, review and examine the progress of transmission and distribution (T&D) reliability since the first SGSR was published. This section examines the reliability of T&D, which is considered a value metric in the SGSR framework. As a value metric rather than a build metric, it will take time to establish which smart grid attributes (e.g., intelligence, communication capability, automation) enhance measurement most accurately. T&D automation is intended to enhance T&D reliability.

There are over 700,000 miles of transmission lines and 2.2 million miles of distribution lines in the United States.[216] U.S. electricity service providers, and the transmission system in particular, have been the focus of political scrutiny due to recent widespread outages, such as the 2003 Northeast power outage and the August 10, 1996, west coast outage. Approximately 92 percent[217] of end-user outages can be traced to problems in the distribution system, most of which are caused by physical damage to the infrastructure such as tree branches falling on distribution lines or damage to underground cables caused by digging. Events in the generation and transmission systems account for only 10 to 20 percent of outages, but these include the largest and most costly events.[218] In 2001, EPRI estimated power-interruption and power-quality cost at $119 billion per year,[219] and a 2004 study from Lawrence Berkeley National Laboratory (LBNL) estimated the cost at $80 billion per year.[220]

Technical progress has recently been made in the area of reliability and cyber standards. More importantly from a reliability perspective, however, progress has also been made in wide-

[216] Beach JL and NC Dilts. 2007. *Electric Transmission & Distribution Infrastructure: Powerful Spending Trend Forecast to Extend Well Into the Next Decade*. Industry Analysis, Winter 2006/2007. Stifel, Nicolaus & Company, Incorporated Equity Research, Baltimore, Maryland. Accessed October 22, 2010 at http://www.classicconnectors.com/downloads/Electric%20Transmission%20and%20Distribution%20Infrastructure%20Report%20-%20Stifel%20Nicolaus%20-%20Reduced.pdf (undated webpage).

[217] Gellings C. May 24, 2004. "Behind the Numbers: A Conversation with Clark Gellings, Vice President of Power, Delivery, and Markets at the Electric Power Research Institute." *EnergyPulse™*. Accessed October 22, 2010 at http://www.energypulse.net/centers/article/article_display.cfm?a_id=696 (last updated May 24, 2004).

[218] Hamachi LaCommare K and JH Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. LBNL-55718, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Accessed October 14, 2008 at http://certs.lbl.gov/pdf/55718.pdf (undated webpage).

[219] CEIDS – Consortium for Electric Infrastructure to Support a Digital Society. 2001. *The Cost of Power Disturbance to Industrial & Digital Economy Companies.* Prepared by Primen for the Electric Power Research Institute, Inc., Palo Alto, California. Accessed October 15, 2008 at http://www.epri-intelligrid.com/intelligrid/docs/Cost_of_Power_Disturbances_to_Industrial_and_Digital_Technology_Companies.pdf (undated webpage).

[220] Hamachi LaCommare and Eto 2004.

area situational awareness and control. Such progress will help to protect the grid from major failures like the 2003 blackout of the Northeast.

Because there is a big difference between transmission and distribution systems in technologies, system miles and sophistication, not to mention cost, transmission and distribution should be considered separately in different contexts, with transmission being an analog to the interstate highway system and distribution analogous to roads and streets. There are numerous common capacity issues shared between the transmission system and the distribution system, including system reliability, power quality and capacity limitations. One of the biggest policy issues facing utilities and regulators is capacity problems across transmission operations areas, known as ISOs. Capacity issues manifest as congestion (overloading) on the transmission system, but are most easily dealt with at the end-use (distribution) level, via demand-response programs, put in place by system operators via individual utilities' program offerings to end users. This has been driven by FERC's effort to lower the cost of ancillary services, which have long been the sole domain of large generation providers.

Smart grid technologies will address transmission congestion issues through demand response, controllable loads, energy storage, distributed renewables and distribution automation. Diagnostic tools within the transmission system and smart-grid-enabled distributed controls (demand response driven by automated interaction of electricity service provider price signals and commercial or residential energy management systems) will help dynamically balance electricity supply and demand, thereby helping the system respond to imbalances and limit their propagation when they occur. These controls and tools could reduce the frequency of outages and power disturbances attributed to grid overload. They could also reduce planned rolling brownouts and blackouts like those implemented during the energy crisis in California in 2000. Smart grid technologies could quickly diagnose outages caused by physical damage of the transmission and distribution facilities due to weather, and could quickly direct crews to repair them in an automated manner rather than the relatively manual outage management systems used today.[221]

[221] Baer WS, B Fulton, and S Mahnovski. 2004. *Estimating the Benefits of the GridWise Initiative: Phase I Report.* TR-160-PNNL. Prepared by Rand Science and Technology for Pacific Northwest National Laboratory, Richland, Washington. Accessed October 15, 2008 at http://www.rand.org/pubs/technical_reports/2005/RAND_TR160.pdf (undated webpage).

A functional objective of the smart grid concept[222] is to enhance reliability of the transmission and distribution systems. Reliability is described by DOE[223] as follows: "A Smart Grid that anticipates, detects and responds to problems rapidly reduces wide-area blackouts to near zero (and will have a similarly diminishing effect on the lost productivity)." A recent DOE report[224] on Smart Grid Benefits addressed this issue by saying:

Two ways that a smart grid can improve reliability are:

- prevent or limit blackouts[225] using wide area control on the transmission level
- rapidly isolate and reconfigure distribution system faults.

Both of these actions can shorten outage durations from hours to as short as minutes.

### A.10.2 Description of Metric and Measurable Elements

Several widely accepted metrics for measuring T&D reliability already exist in the industry. The System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI) describe the duration and frequency of sustained interruptions experienced by customers of an electricity service provider in one year.[226] These metrics are the focus of this paper.

(Metric 10.a) SAIDI represents the average number of minutes customers' power is interrupted each year, and is calculated as

$$SAIDI = \frac{\text{Sum of customer (sustained) interruption durations for all customers}}{\text{Total number of customers served}}.$$

[222] OE – Office of Electricity Delivery and Energy Reliability. Undated. *Smart Grid*. Office of Electricity Delivery and Energy Reliability, Washington, D.C. Accessed October 22, 2010 at http://www.oe.energy.gov/smartgrid.htm (undated webpage).

[223] Litos Strategic Communication. 2008. *The Smart Grid: An Introduction*, p. 37. Prepared by Litos Strategic Communication for the U.S. Department of Energy, Washington, D.C. Accessed October 22, 2010 at http://www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages%281%29.pdf (undated webpage).

[224] Pratt RG, MCW Kintner-Meyer, PJ Balducci, TF Sanquist, C Gerkensmeyer, KP Schneider, S Katipamula, and GJ Secrest. 2010. *The Smart Grid: An Estimation of the Energy and $CO_2$ Benefits*. PNNL-19112 Rev 1, Pacific Northwest National Laboratory, Richland, Washington. Accessed July 21, 2010 at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf (undated webpage).

[225] Galvin F and C Wells. Undated. *Detecting and Managing the Electrical Island Created by Hurricane Gustav*. North American SynchroPhasor Initiative. Accessed October 22, 2010 at http://www.naspi.org/stories/pilot_fundamental/entergy_hurricane_gustav.pdf (undated webpage).

[226] IEEE – Institute of Electrical and Electronics Engineers. 1995. *IEEE Recommended Practice for Monitoring Electric Power Quality.* IEEE Standard 1159-1995, Institute of Electrical and Electronics Engineers, Inc., Piscataway, New Jersey. Accessed October 22, 2010 at http://www.apqi.org/file/attachment/2008721/113112.pdf (undated webpage).

(Metric 10.b) SAIFI represents the total number of power interruptions per customer for a particular electric supply system, and is calculated as

$$SAIFI = \frac{\text{Total number of customer (sustained) interruptions for all customers}}{\text{Total number of customers served}}.$$

(Metric 10.c) CAIDI represents the average outage duration that a customer experiences; alternatively stated, it is the average restoration time.

$$CAIDI = \frac{\text{Sum of durations of all customer interruptions}}{\text{Total number of customer interruptions}} = \frac{SAIDI}{SAIFI}.$$

(Metric 10.d) MAIFI represents the total number of customer interruptions per customer lasting less than five minutes for a particular electric supply system, and is calculated as

$$MAIFI = \frac{\text{Total number of momentary } (< 5 \text{ min}) \text{ interruptions for all customers}}{\text{Total number of customers served}}.$$

### A.10.3 Deployment Trends

A recent study by LBNL on the cost of T&D reliability incidents compared several different studies that examined national statistics on SAIDI, SAIFI and MAIFI. The findings are presented in Table A.9. LBNL also compiled data and calculated values at the regional level. These regional indices are shown in Table A.10.

**Table A.9**. Summary of U.S. Reliability Event Estimates[227]

| | SAIFI | SAIDI | MAIFI |
|---|---|---|---|
| EPRI Report | 1.1 | 107 | |
| IEEE 1995 Survey | 1.3 | 120 | 5.5 |
| EEI Annual Report | | | |
| 1998 | 1.2 | 118 | 5.4 |
| 1999 | 1.4 | 101 | 11.6 |

[227] Hamachi LaCommare and Eto 2004.

**Table A.10**. Regional Variation in Collected Reliability Event Data[228]

| Region # | Region Name | SAIDI | SAIFI | MAIFI |
|---|---|---|---|---|
| 1 | New England | 131 | 1.1 | N/A |
| 2 | Middle Atlantic | 115 | 1.0 | 9.5 |
| 3 | East North Central | N/A | N/A | N/A |
| 4 | West North Central | 63 | 0.8 | 11.2 |
| 5 | South Atlantic | N/A | N/A | N/A |
| 6 | East South Central | N/A | N/A | N/A |
| 7 | West South Central | 95 | 1.3 | N/A |
| 8 | Mountain | 92 | 1.1 | 3.5 |
| 9 | Pacific | 105 | 1.2 | 3.2 |
| 10 | California | 138 | 1.3 | 2.3 |
| U.S. | U.S. Total | 106 | 1.2 | 4.3 |

Another more recent study[229] by LBNL provided a more detailed summary of SAIDI, SAIFI, and MAIFI data than the 2004 data cited above (Table A.11).

**Table A.11**. Regional SAIDI, SAIFI, and MAIFI Data

| Census Division | Sales as Percentage of Total IOU Sales in Region | Sales as Percentage of Total U.S. Sales in Region | SAIDI (Minutes) | | | SAIFI | | | MAIFI | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | N | Avg | Std Dev | N | Avg | Std Dev | N | Avg | Std Dev |
| New England | 99% | 68% | 16 | 198 | 130 | 16 | 1.44 | 0.62 | ND | ND | ND |
| Middle Atlantic | 100% | 75% | 21 | 225 | 188 | 21 | 1.28 | 0.55 | ND | ND | ND |
| East North Central | 75% | 62% | 19 | 498 | 895 | 19 | 1.46 | 0.48 | ND | ND | ND |
| West North Central | 57% | 35% | 12 | 166 | 202 | 12 | 1.31 | 0.68 | 2 | 5.11 | 5.03 |

[228] Hamachi LaCommare and Eto 2004.

[229] Eto JH and K Hamachi LaCommare. 2008. *Tracking the Reliability of the U.S. Electric Power System: An Assessment of Publicly Available Information Reported to State Public Utility Commissions*. LBNL-1092E, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Accessed October 22, 2010 at http://certs.lbl.gov/pdf/lbnl1092e-puc-reliability-data.pdf (undated webpage).

**Table A.11**. (contd)

| Census Division | Sales as Percentage of Total IOU Sales in Region | Sales as Percentage of Total U.S. Sales in Region | SAIDI (Minutes) | | | SAIFI | | | MAIFI | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| South Atlantic | 71% | 53% | 18 | 320 | 200 | 18 | 1.86 | 0.62 | 4 | 11.1 | 2.16 |
| East South Central | 0% | 0% | ND | ND | ND | ND | ND | ND | ND | ND | ND |
| West South Central | 88% | 30% | 18 | 134 | 56 | 18 | 1.38 | 0.46 | ND | ND | ND |
| Mountain | 35% | 27% | 7 | 118 | 58 | 7 | 1.22 | 0.54 | ND | ND | ND |
| Pacific | 99% | 62% | 12 | 296 | 214 | 12 | 1.99 | 1.21 | 6 | 3.40 | 2.35 |
| U.S. | 77% | 58% | 123 | 244 | 243 | 123 | 1.49 | 0.64 | 12 | 6.55 | 3.18 |

Note: N = Number of Reported Values; Avg = Average; Std Dev = Standard Deviation; ND = No Data. IOU = investor owned utility

The IEEE's 2005 benchmarking study[230] analyzed data from 55 companies out of more than 3,000 U.S. utilities between 2000 and 2005. Results showed an 8 percent increase in CAIDI, a 21 percent increase in SAIDI, and a 13 percent increase in SAIFI. The national trends are shown in Figure A.18.

[230] IEEE – Institute of Electrical and Electronics Engineers. 2006. *IEEE Working Group on Distribution Reliability, Benchmarking 2005 Results*. July 2006, Institute of Electrical and Electronics Engineers, Inc., Piscataway, New Jersey. Accessed October 15, 2008 at http://grouper.ieee.org/groups/td/dist/sd/doc/2006-07-BenchmarkingUpdate.pdf (undated webpage).

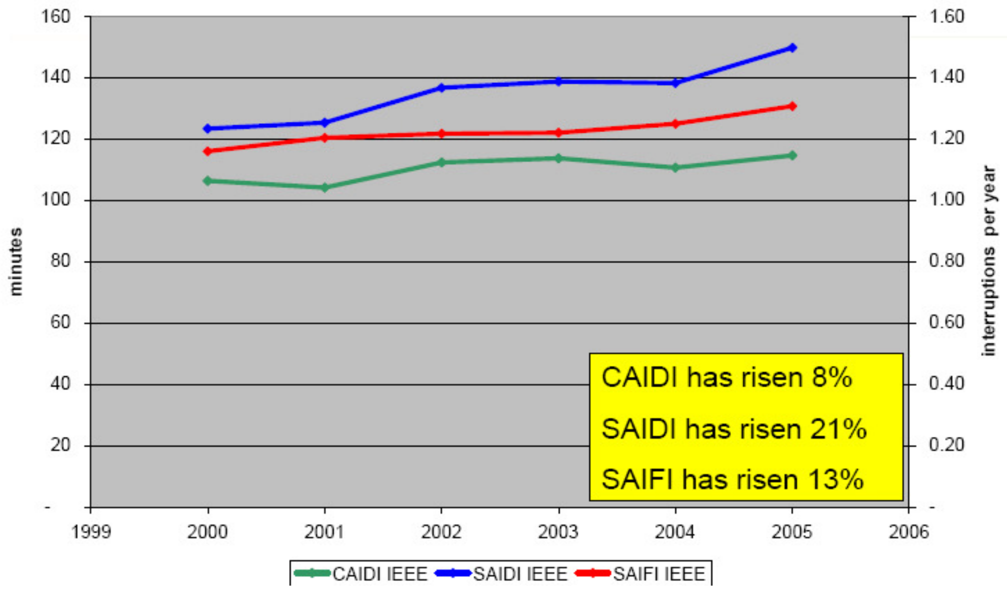



**Figure A.18**. Trends for 55 Utilities Providing Data between 2000 and 2005[231]

The IEEE's 2008 benchmarking study[232] analyzed data from 62 companies. SAIDI, SAIFI, and CAIDI data broken down by respondent size are shown in Table A.12. The all data categories include previous years' data from 2003 to 2006.

**Table A.12**. SAIDI, SAIFI, and CAIDI by Respondent Size

| Small Respondents 2007 | | | | | | |
|---|---|---|---|---|---|---|
| Quartile | SAIDI IEEE | SAIDI All | SAIFI IEEE | SAIFI All | CAIDI IEEE | CAIDI All |
| 1 | 94.63 | 94.63 | 1.00 | 1.27 | 71.60 | 79.54 |
| 2 | 110.52 | 151.87 | 1.617 | 1.96 | 84.24 | 99.18 |
| 3 | 187.17 | 261.50 | 2.31 | 2.40 | 87.01 | 116.60 |
| 4 | 244.70 | 525.46 | 2.766 | 3.71 | 105.75 | 141.50 |
| Medium Respondents 2007 | | | | | | |
| Quartile | SAIDI IEEE | SAIDI All | SAIFI IEEE | SAIFI All | CAIDI IEEE | CAIDI All |
| 1 | 119.36 | 158.88 | 1.19 | 1.33 | 94.13 | 110.54 |
| 2 | 156.33 | 220.39 | 1.44 | 1.70 | 110.95 | 138.92 |
| 3 | 206.72 | 412.40 | 1.70 | 2.06 | 120.56 | 213.07 |
| 4 | 385.94 | 958.86 | 3.20 | 3.97 | 174.72 | 466.68 |

[231] IEEE 2006.

[232] IEEE – Institute of Electrical and Electronics Engineers. 2009. *IEEE Working Group on Distribution Reliability, Benchmarking 2007 Results*. January 2009. Institute of Electrical and Electronics Engineers, Inc., Piscataway, New Jersey. Accessed July 20, 2010 at http://grouper.ieee.org/groups/td/dist/sd/doc/2009-01-01-Benchmarking-Results-2007.pdf (undated webpage).

**Table A.12**. (contd)

| Large Respondents 2007 | | | | | | |
|---|---|---|---|---|---|---|
| Quartile | SAIDI IEEE | SAIDI All | SAIFI IEEE | SAIFI All | CAIDI IEEE | CAIDI All |
| 1 | 105.49 | 145.65 | 0.93 | 1.13 | 88.66 | 104.44 |
| 2 | 135.89 | 208.27 | 1.12 | 1.39 | 120.42 | 146.65 |
| 3 | 170.48 | 284.33 | 1.45 | 1.82 | 133.37 | 203.45 |
| 4 | 257.08 | 824.05 | 2.11 | 2.24 | 205.81 | 455.73 |

The smart grid interviews conducted for the SGSR asked utilities to present SAIDI, SAIFI, and MAIFI data for the most recent year for which data were available and compare actual data against the levels predicted prior to the year in question; findings from the interviews are summarized in Table A.13. Responses from each electricity service provider were weighted based on their share of the total customer base of those utilities providing data.

**Table A.13**. Predicted and Actual SAIFI, SAIDI, and MAIFI

| Metric Name | Predicted | Actual |
|---|---|---|
| SAIFI | 0.81 | 1.13 |
| SAIDI | 63.94 | 115.32 |
| MAIFI | 0.23 | 1.46 |

Due primarily to the economic recession, forecast peak electricity demand in NERC's 2010 Long Term Reliability Assessment has dropped 4.1 percent since the 2009 forecast, and 7.8 percent since the current economic downturn began. Presently, NERC forecasts annual demand growth of 1.34 percent between 2010 and 2019, resulting in peak (summer) demand rising from 772 GW to 870 GW.[233] Planning-reserve margins demonstrate the forecast difference between capacity and peak electricity demand. Prospective systems are those planned or under construction, while deliverable systems represent those already on line. Figure A.19 presents the forecast reserve margins from 2009 to 2018. The rise in the near term reflects the current decrease in overall electricity demand. As the U.S. economy recovers and demand rises, reserve margins are forecast to decrease. Although reserve margins presented in this aggregated graph are not forecast to fall below the 15 percent NERC reference level, regional projections vary significantly.

[233] NERC - North American Electric Reliability Corporation. 2010. *2010 Long-Term Reliability Assessment 2010-2019*. North American Electric Corporation, Princeton, New Jersey. Accessed November 29, 2010 at http://www.nerc.com/files/2010%20LTRA.pdf (undated webpage).

NERC's *2009 Long Term Reliability Assessment*[234] shows an increase in reserve margins in many regions, due in large part to the economic recession, along with an increase in demand-side management programs and the addition of new resources. The NERC report also includes additional information which shows in-depth reliability information by NERC regions. Figure A.20 includes an assessment summary for the Western Electricity Coordinating Council. This additional information includes demand-side management estimates, capacity margin broken into various time frames, and other predictive information.

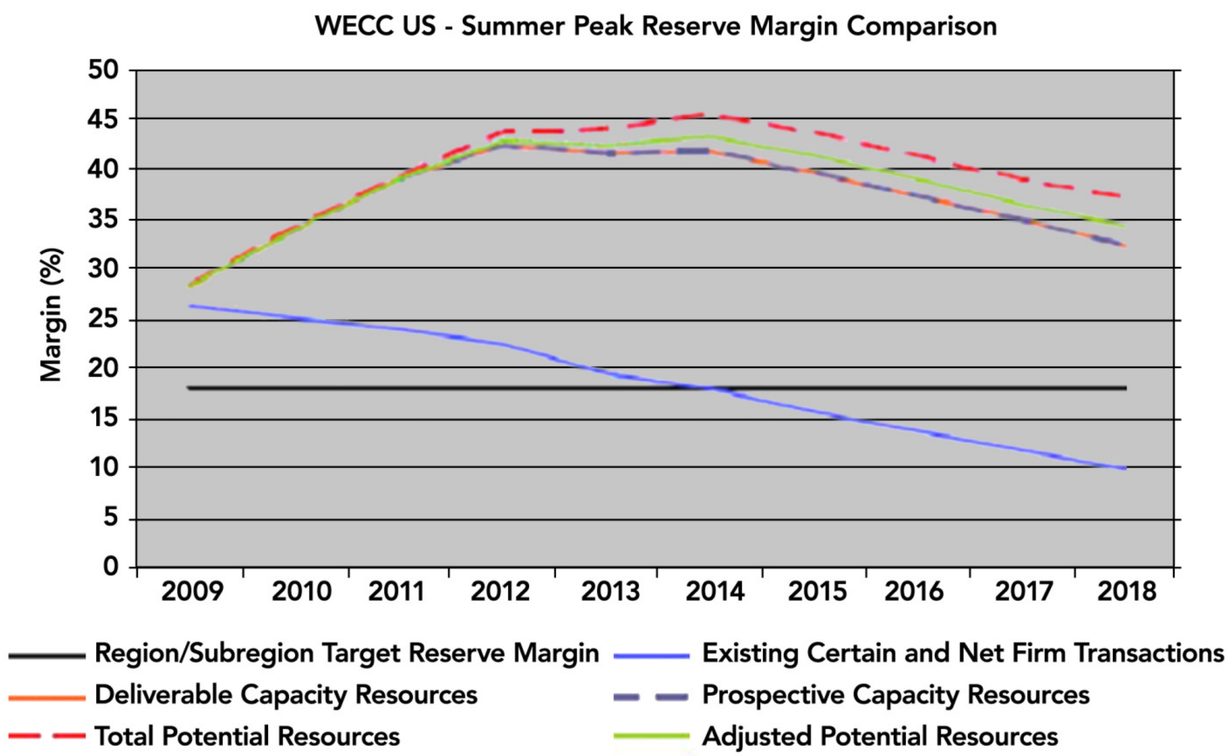
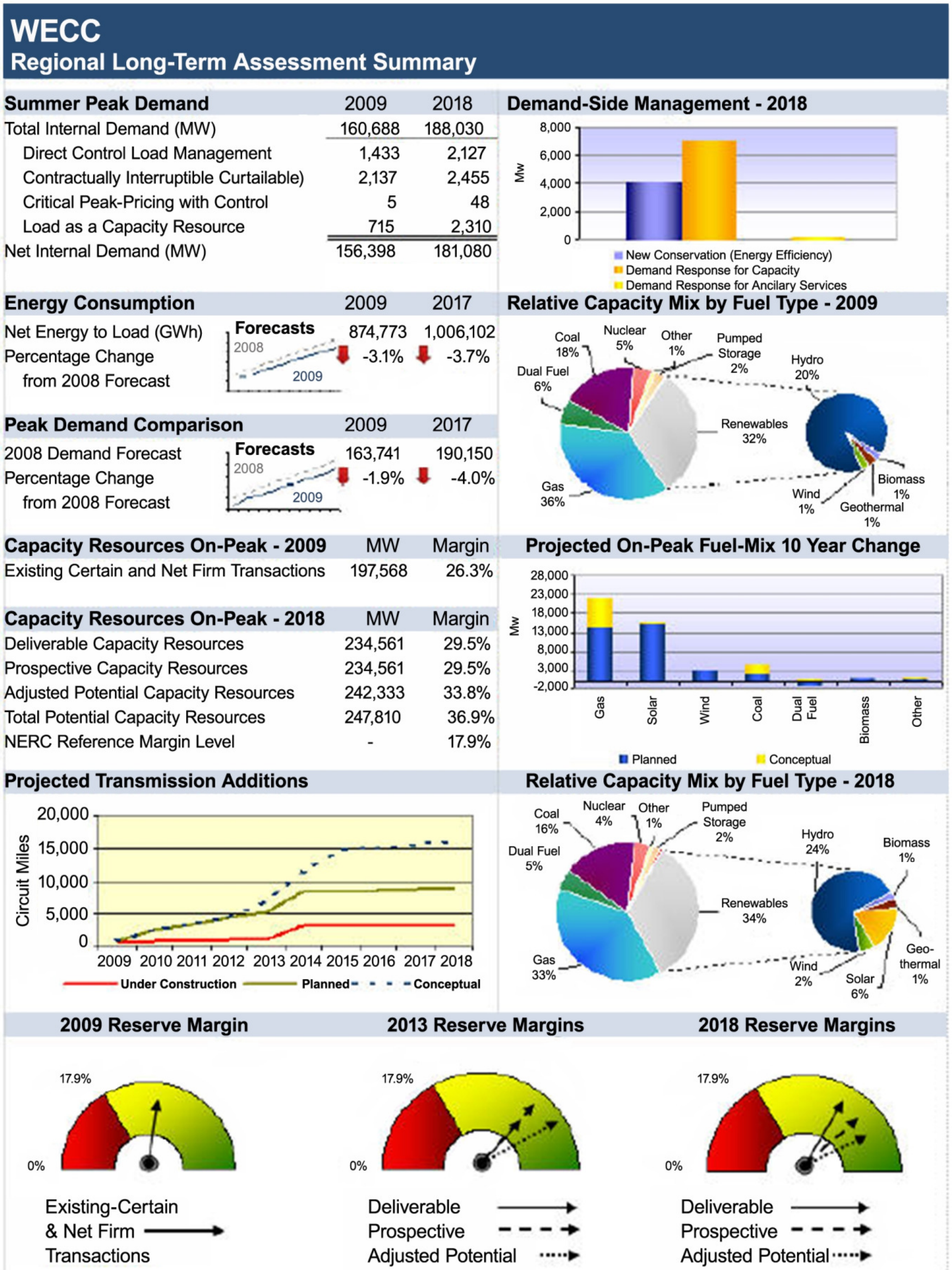



**Figure A.19**. Forecast Summer Peak Reserve Margin

[234] NERC – North American Electric Reliability Corporation. 2009. *2009 Long-Term Reliability Assessment: 2009-2018*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed July 22, 2010 at http://www.nerc.com/files/2009_LTRA.pdf (undated webpage).



## WECC
## Regional Long-Term Assessment Summary

| Summer Peak Demand | 2009 | 2018 |
|---|---|---|
| Total Internal Demand (MW) | 160,688 | 188,030 |
| Direct Control Load Management | 1,433 | 2,127 |
| Contractually Interruptible Curtailable) | 2,137 | 2,455 |
| Critical Peak-Pricing with Control | 5 | 48 |
| Load as a Capacity Resource | 715 | 2,310 |
| Net Internal Demand (MW) | 156,398 | 181,080 |

| Energy Consumption | 2009 | 2017 |
|---|---|---|
| Net Energy to Load (GWh) | 874,773 | 1,006,102 |
| Percentage Change from 2008 Forecast | -3.1% | -3.7% |

| Peak Demand Comparison | 2009 | 2017 |
|---|---|---|
| 2008 Demand Forecast | 163,741 | 190,150 |
| Percentage Change from 2008 Forecast | -1.9% | -4.0% |

| Capacity Resources On-Peak - 2009 | MW | Margin |
|---|---|---|
| Existing Certain and Net Firm Transactions | 197,568 | 26.3% |

| Capacity Resources On-Peak - 2018 | MW | Margin |
|---|---|---|
| Deliverable Capacity Resources | 234,561 | 29.5% |
| Prospective Capacity Resources | 234,561 | 29.5% |
| Adjusted Potential Capacity Resources | 242,333 | 33.8% |
| Total Potential Capacity Resources | 247,810 | 36.9% |
| NERC Reference Margin Level | - | 17.9% |



**Figure A.20**. WECC Regional Long-Term Assessment Summary[235]

[235] NERC 2009.

#### A.10.3.1 Associated Stakeholders

There are a number of stakeholders with interests in transmission and distribution reliability:

- electric-service retailers wanting to cost-effectively provide a more reliable product[236]
- end users (consumers) needing reliable power, at the 99.99 percent level—less than an hour per year of total outage time
- local, state, and federal energy policymakers concerned with the negative economic effects of poor power quality on commercial and industrial customers
- regulators who decide the basic level of power quality and reliability that the system will provide to customers.

#### A.10.3.2 Regional Influences

Reporting regulations and practices vary from state to state, making it difficult to compare data such as the above-mentioned metrics across regions. Regional differences arise for several reasons, including climate, geography, and design and maintenance of the distribution system. Some utilities will naturally have better reliability indices than others due to differences in geography and natural vegetation and in frequency and types of severe weather in the region. For example, the number of lightning strikes, the length of exposed feeders, and urban network-system designs have a significant impact on reliability figures, regardless of the utilities' ability to operate and maintain their systems.[237] Each region of the country has a different combination (weighting) of customers (residential, commercial, and industrial) and each electricity service provider has its own unique distribution system, all of which affect T&D reliability.

The 2006 *National Electric Transmission Congestion Study* conducted by DOE investigated the eastern and western interconnections to identify constrained transmission paths of national interest. Transmission congestion can indicate areas of system stress that can affect reliability as well as the cost of electricity. Using scenarios projecting fuel prices for 2008 and 2011, the study identified 118 paths in the eastern interconnection that would be congested under almost every scenario. The western analysis modeled significantly larger nodes than the east and identified ten paths that were likely to be the most heavily congested in their 2008

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[236] Longley R. 2005. "Power Interruptions Cost Nation $80 Billion Annually." *About.com*. Accessed October 22, 2010 at http://usgovinfo.about.com/od/consumerawareness/a/poweroutcosts.htm (undated webpage).

[237] Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices*. ORNL/TM-2004/91. Prepared by Oak Ridge National Laboratory for the U.S. Department of Energy, Washington, D.C. Accessed October 14, 2008 at http://www.ornl.gov/sci/engineering_science_technology/eere_research_reports/power_systems/reliability_and_power_quality/ornl_tm_2004_91/ornl_tm_2004_91.pdf (undated webpage).

projections, ordered by the number of hours during which usage is 90 percent or more of a line's limit. Overall, the study identified two critical congestion areas: 1) the Atlantic coastal area from New York to northern Virginia, and 2) southern California. Four congestion areas of concern were also identified (one in the east and three in the west). Five conditional congestion areas were also listed as situations to watch. It should be noted that DOE did not include ERCOT in their study, because it was explicitly excluded in their directive from the Energy Policy Act of 2005.[238]

One of the biggest coming issues with regard to transmission reliability is integration of renewable resources such as wind and solar. The power from these resources needs to be moved from remote areas to population centers; the American Wind Energy Association sees this as an important issue.[239]

## A.10.4 Challenges to Deployment

### A.10.4.1 Technical Challenges

Technical challenges include combining new technologies with existing technologies and updating the existing grid. Unique characteristics of wind, solar, and nuclear power generation must be taken into account when planning for the future. A recent NERC survey of industry professionals ranked aging infrastructure and limited new construction as the number one challenge to reliability—both in likelihood of occurrence and potential severity. Lastly, more standardized codes, requirements, and reporting of T&D reliability are needed.[240]

### A.10.4.2 Business and Financial Challenges

Upgrading and adding to the grid incurs costs that some may hesitate to take on. FERC, in a policy statement on matters related to bulk power system reliability, stated that public electricity service providers may be reluctant to spend significant amounts of money without reassurance that they will be able to recover it. The report goes on to note:

*Regulators should clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. The Commission also assures*

[238] DOE – U.S. Department of Energy. 2006. *National Electric Transmission Congestion Study.* U.S. Department of Energy, Washington, D.C. Accessed May 27, 2009 at http://www.oe.energy.gov/DocumentsandMedia/Congestion_Study_2006-9MB.pdf (undated webpage).

[239] Goggin M. July 30, 2008. "Interstate Transmission Superhighways: Paving the Way to a Low-carbon Future." *RenewableEnergyWorld.com*. Accessed July 22, 2010 at http://www.renewableenergyworld.com/rea/news/article/2008/07/interstate-transmission-superhighways-paving-the-way-to-a-low-carbon-future-53193 (last updated July 30, 2008).

[240] FERC – Federal Energy Regulatory Commission. 2007. *Results of the 2007 Survey of Reliability Issues*, Rev 1. The Federal Regulatory Commission, Washington, D.C. Accessed February 6, 2009 at http://www.nerc.com/files/Reliability_Issue_Survey_Final_Report_Rev.1.pdf (undated webpage).

*public utilities that they will approve applications to recover prudently incurred costs necessary to ensure bulk electricity system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices.*[241]

Because of the complex interaction of electricity service provider reliability programs and technologies, it can be difficult for them to prove to regulators the exact cost/value relationship of particular measures, and the consequent cautious response by electricity service providers to implementing power quality measures can make regulators hesitant to allow cost recovery.

A large portion of the electricity service provider workforce is approaching retirement without a skilled workforce to take their place. Utilities need to actively recruit and train skilled labor to ensure a knowledgeable workforce for the future. Lastly, educating and demonstrating to end users the use of smart-grid-enabled programs, such as dynamic pricing, should be a priority.

Currently, there are irregularities in the ways utilities and regions report T&D reliability incidents. Definitions are sometimes vague, and inconsistencies in reporting requirements are making it difficult to complete analyses. For example, SAIDI, SAIFI, and MAIFI are useful for assessing T&D reliability, but often are not collected, or are collected inconsistently.[242] In a 2003 nationwide study by IEEE, several inconsistencies between electricity service provider practices were found. They found disparity in how start and end times of an interruption are reported and wide discrepancies in what defines a major event that would be excluded from reliability indices; some utilities include MAIFI within SAIFI, which inflates SAIFI. Utilities differ on the level at which they measure reliability (e.g., substation, circuit breaker, meter), and interruption data is entered differently, either automatically by a computer or manually.[243]

Another factor of potential impact on reliability measurements is the way states regulate reliability, which can drive strategies for how to meet regulatory goals for reliability. Figure A.21 shows the types of strategies[244] that various states use to drive reliability requirements.

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[241] FERC – Federal Energy Regulatory Commission. April 19, 2004. *Policy Statement on Matters Related to Bulk Power System Reliability*. Docket No. PL04-5-000. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 14, 2008 at http://www.ferc.gov/whats-new/comm-meet/041404/E-6.pdf (undated webpage).

[242] Kueck et al. 2004.

[243] Warren CA, DJ Pearson, and MT Sheehan. 2003. "A Nationwide Survey of Recorded Information Used for Calculating Distribution Reliability Indices." *IEEE Transactions on Power Delivery* 18(2):449-453, DOI: 10.1109/TPWRD.2002.803693. Accessed November 26, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=1193863&isnumber=26850 (undated webpage).

[244] Layton L. 2004. *Electric System Reliability Indices*. L2 Engineering, Lenoir, North Carolina. Accessed July 22, 2010 at http://www.l2eng.com/Reliability_Indices_for_Utilities.pdf (undated webpage).

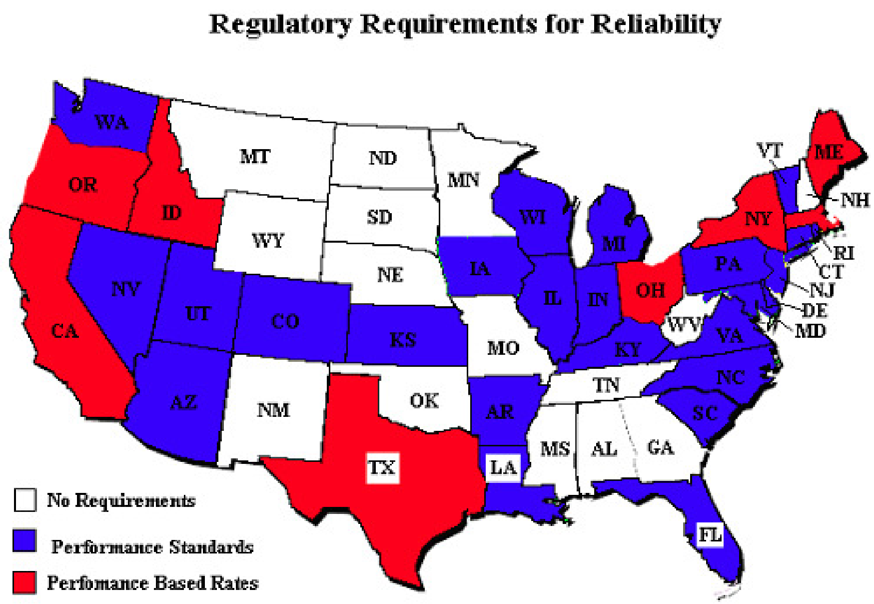


**Figure A.21**. Regulatory Requirements for Reliability

### A.10.5 Metric Recommendations

More interviews should be conducted in support of future smart grid benchmark studies and a single data source should be identified for national statistics covering SAIDI, SAIFI, CAIDI, and MAIFI. Support for a single source would allow analysts to compare trends over time in a consistent manner. Options for improved reporting could include a FERC requirement for reporting the metrics used in this report, essentially IEEE 1366 data, at both the transmission and distribution levels, to FERC and state regulators.

# A.11 Metric #11: Transmission and Distribution Automation

## A.11.1 Introduction and Background

T&D automation is defined by IEEE as "a system that enables an electricity service provider to remotely monitor, coordinate, and operate [transmission and] distribution components in a real-time mode from remote locations." This metric includes coordination between electric T&D components that are separate, but co-located. This broad definition encompasses a large set of technologies, which include SCADA technologies, remote sensors and monitors, switches and controllers with embedded intelligence, digital relays, and a large number of other technologies used in the T&D infrastructure. The general operating scheme of these devices is to gather real-time information about the grid through communication and coordination with other devices, process the information on site, take immediate corrective action if necessary, and communicate results back to human operators or other systems. These devices serve a variety of functions, including "fault location, fault isolation, feeder reconfiguration, service restoration, remote equipment monitoring, feeder load balancing, Volt-VAR controls, remote system measurements, and other options."[245] If operated properly, T&D automation systems can provide more reliable and cost-effective operation through increased responsiveness and system efficiency.

Smart grid investment has become a popular market research topic. Aided by energy efficiency initiatives, renewable portfolio standards and government stimulus actions, public and private funding of smart grid applications has grown during the past few years. According to a new report from Pike Research, global spending on smart grid technologies is estimated to top $200 billion between 2008 and 2015, with grid automation systems capturing 84 percent of the market and AMI capturing 14 percent.[246]

Financed by ARRA in 2009, DOE's Smart Grid Investment Grant (SGIG) program has funded a wide range of technology to add automation features to the U.S. grid. The SGIG program is investing 3.4 billion dollars over a time period of 3 to 5 years. There are 671 substation automation projects in the SGIG investment program,[247] representing 5 percent of the total 12,466 T&D substations in the U.S.

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[245] Uluski R. May 21, 2007. "Is Distribution Feeder Automation Right for You and Your Customers?" *EnergyPulse.* Accessed October 28, 2008 at http://www.energypulse.net/centers/article/article_print.cfm?a_id=1481 (undated webpage).

[246] Pike Research. December 28, 2009. "Smart Grid Investment to Total $200 Billion Worldwide by 2015." Pike Research, Boulder, Colorado. Accessed July 21, 2010 at http://www.pikeresearch.com/newsroom/smart-grid-investment-to-total-200-billion-worldwide-by-2015 (last updated December 28, 2009).

[247] Ton D. 2009. *DOE's Perspectives on Smart Grid Technology, Challenges, & Research Opportunities.* Presented at the UCLA HSSEAS Smart Grid Seminar Series. November 19, 2009, Los Angeles, California. Accessed October 26, 2010 at http://www.ita.ucla.edu/news/presentations/Ton-UCLA1119-rv.pdf (undated webpage).

### A.11.2 Description of the Metric and Measurable Elements

The metric for automation technology adoption is defined as:

(Metric 11) Percentage of substations having automation.

### A.11.3 Deployment Trends and Projections

Data from utilities across the nation show a clear trend of increasing T&D automation and increasing investment in these systems. Key drivers for the increase in investment include operational efficiency and reliability improvements to drive cost down and overall reliability up. The lower cost of automation with respect to T&D equipment (e.g., transformers, conductors) is also making the value proposition easier to justify. With higher levels of automation in all aspects of T&D operation, operational changes can be introduced to operate the system closer to capacity and stability constraints.

Weighted results of interviews undertaken for this report (see Appendix B) indicate that:

- 47.7 percent of the total substations owned by electric services providers interviewed for this study were automated.
- 78.2 percent of the total substations owned had outage detection.
- 82.1 percent of total customers had circuits with outage detection.
- 46.4 percent of total relays were electromechanical relays.
- 13.4 percent of total relays were microprocessor-based relays.

Other nationwide data has shown that transmission automation has already penetrated the market highly, while distribution automation is primarily led by substation automation, with feeder equipment automation still lagging. Recent research shows that while 84 percent of utilities had substation automation and integration plans underway in 2005, and about 70 percent of utilities had deployed SCADA systems to substations, the penetration of feeder automation is still limited to about 20 percent.[248,249] Because feeder automation lags other automation efforts so significantly, this should be an area addressed directly in future work.

[248] Moore D and D McDonnell. 2007. "Smart Grid Vision Meets Distribution Utility Reality." *Electric Light and Power*. Accessed November 21, 2008 at http://www.elp.com/index/display/article-display/289077/articles/electric-light-power/volume-85/issue-2/sections/finance/smart-grid-vision-meets-distribution-utility-reality.html (undated webpage).

[249] McDonnell D. November 7, 2006. "Beyond the Buzz: The Potential of Grid Efficiency." *SmartGridNews.com*. Accessed November 21, 2008 at http://www.smartgridnews.com/artman/publish/industry/Beyond_the_Buzz_The_Potential_of_Grid_Efficiency_180_printer.html (last updated November 7, 2006).

It is worth noting that, aside from the survey data that is presented here, there is a relative lack of data about the penetration of transmission and distribution automation. Differences in how these devices are operated make it difficult to directly draw conclusions about the impact of these devices on the actual performance of the grid.

A significant component of the measurement, analysis, and control of the T&D infrastructure relates to control centers at the transmission and distribution levels of the system (SCADA, transmission-level EMS, and DMS). According to a recent survey by Newton-Evans Research, almost all utilities with over 25,000 customers have SCADA/EMS systems in place, while only about 17 percent of utilities have DMS systems.[250] One smart grid trend is to integrate other functions with these centers. For example, about 30 percent of the SCADA/EMS systems are linked to Distribution Automation/DMS. Figure A.22 shows the projected integration of EMS/SCADA/DMS systems to a variety of other data systems by 2010.

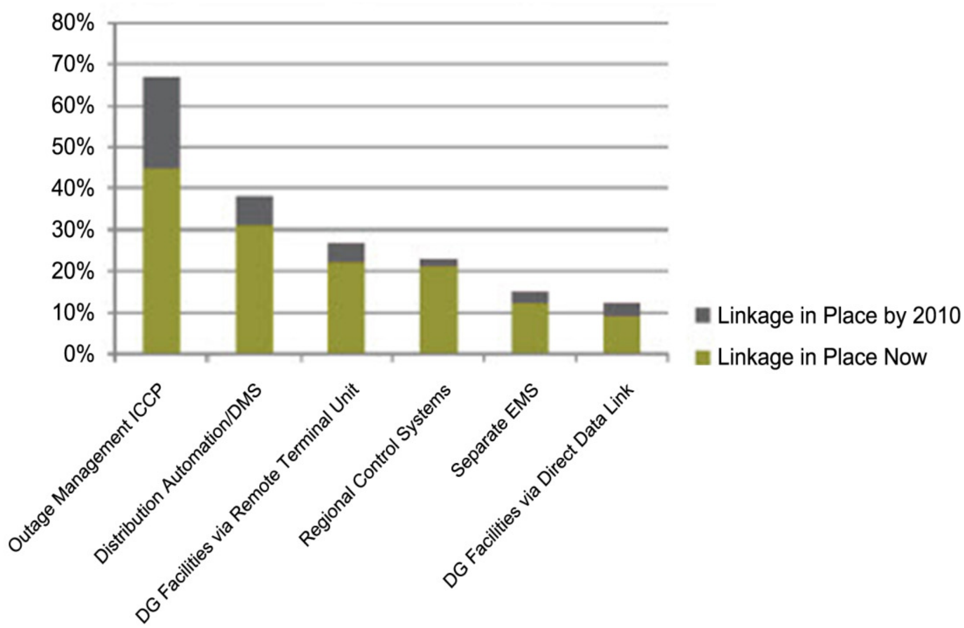


**Figure A.22**. Current/Future Plans for Connecting EMS/SCADA/DMS Systems to Other Data Systems[251]

Transmission and distribution automation technology development and deployment is expected to grow in the future due to higher capital expenditures (CAPEX) by utilities. Recent studies indicate that 2010 electricity service provider investments in T&D infrastructure held

[250] Newton-Evans Research Company. 2008. *Market Trends Digest*. Newton-Evans Research Company, Endicott City, Maryland. Accessed November 11, 2008 at http://www.newton-evans.com/mtdigest/mtd3q08.pdf (undated webpage).
[251] Newton-Evans 2008.

steady despite the current economic climate. Figure A.23 illustrates various smart grid expenditures in 2007 and 2010.

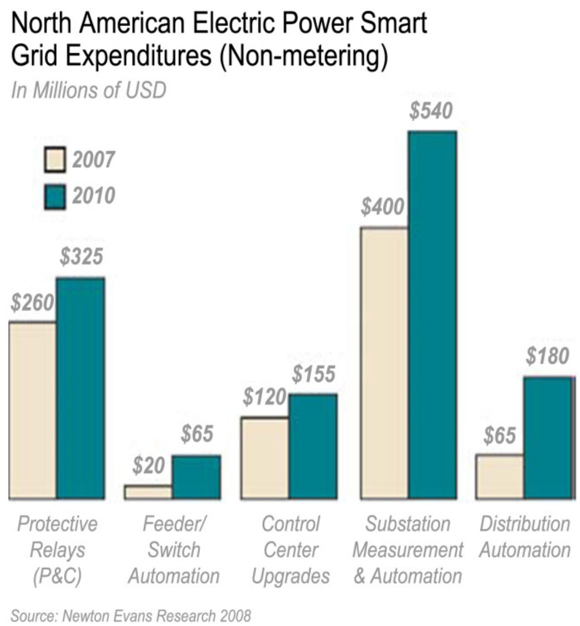


**Figure A.23**. North American Electric Power T&D Automation Expenditures (in Millions of USD)[252,253]

Results from a multi-year study by Newton-Evans regarding electricity service provider CAPEX budgets, presented in Table A.14, generally were positive compared to 2008 and 2009. Organizations from 25 countries participated in the study, and a majority indicated that planned T&D budgets increased or were unchanged in 2010.[254]

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[252] Newton-Evans 2008.

[253] Ockwell G. May 1, 2008. "The Smart Grid Reaches Main Street USA." *Utility Automation & Engineering T&D* 13(5). Accessed October 28, 2008 at http://www.elp.com/index/display/article-display/328726/articles/utility-automation-engineering-td/volume-13/issue-5/features/the-smart-grid-reaches-main-street-usa.html (undated webpage).

[254] EON – Enhanced Online News. March 3, 2010. "Newton-Evans Research Company Utility CAPEX Report Published for 2010-2011 Outlook Period." Accessed July 21, 2010 at http://eon.businesswire.com/news/eon/20100303006780/en/CapEx/smart-grid-investment/Transmission-and-Distribution (last updated March 3, 2010).

**Table A.14**. Comparison of 2010 Planned CAPEX Investment for Smart Grid Programs[255]

| Smart Grid Component and Infrastructure Category | Increase (2009 to 2010) | No Change (2009 to 2010) | Decrease (2009 to 2010) | North American 2010 Investment Range (Mill USD) | Global 2010 Investment Range (Mill USD) |
|---|---|---|---|---|---|
| EMS/SCADA/DMS | 39% | 49% | 12% | $90-$135 | $450-$550 |
| Substation Automation & Integration | 44% | 52% | 4% | $270-$350 | $800-$950 |
| Protection & Control Relays | 46% | 46% | 8% | $490-$540 | $1,750-$2,150 |
| Distribution Automation and Field Intelligent Electronic Devices (IEDs) | 42% | 50% | 8% | $750-$800 | $2,100-$2,400 |
| AMI | 44% | 53% | 4% | $1,300-$1,400 | $3,100-$3,500 |
| Transmission Infrastructure | 44% | 43% | 13% | $10,000-$11,500 | $50,000-$58,000 |
| Distribution Infrastructure | 33% | 50% | 17% | $9,000-$9,750 | $45,000-$52,000 |

CAPEX expenditures data are also included in a Price Coopers Waterhouse report[256] (Figure A.24), which outlines spending from 2004 to 2009 and includes estimations of investment between 2010 and 2012.

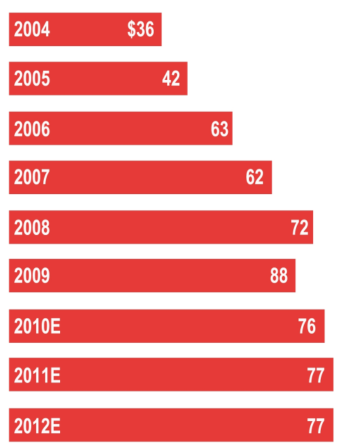


**Figure A.24**. U.S. Electricity Service Provider Capital Expenditure (2004 to 2012 estimate—$billion)

[255] EON 2010.
[256] Sulavik C. 2010. *Smart Grid Growing Pains*. PricewaterhouseCoopers, LLP. Accessed July 21, 2010 at http://www.pwc.com/us/en/technology/assets/smart-grid.pdf (undated webpage).

#### A.11.3.1 Stakeholder Influences

The major stakeholders in the T&D automation arena are those that are directly affected by the performance of this infrastructure, including

- transmission providers as owners and operators of the assets to be maintained and upgraded
- distribution-service providers as owners and operators of the assets to be maintained and upgraded
- local, state, and federal energy policy makers – local governments as regulatory entities for publicly owned companies, state regulators as regulatory entities for investor-owned T&D companies, federal regulators as enforcement entities for reliability; for investor-owned T&D companies, state regulators as regulatory entities approving rate structures
- financial community – will need to provide capital for the required upgrades
- reliability coordinators – ensuring that electricity quality and reliability are maintained
- balancing authorities – will benefit from utilization and efficiency in the delivery system
- vendors – provide technology and enhancements
- end users – consumers, who stand to gain from more cost-effective reliability.

#### A.11.3.2 Regional Influences

While transmission is relatively homogeneous nationwide, distribution networks vary widely among electricity operators. Operators differ in the design and sizing of distribution-system components, which is manifested in the level of system loading. Some operators maintain their feeders at a maximum of 50 percent loading, allowing a single other line to pick up the load of a failed feeder. Others allow their feeders to reach 66 or 100 percent loading, reflecting different operation and contingency schemes.[257] Some of these differences are due to historical or institutional reasons within the company. Other differences are driven by regulators or by state policy. These characteristics will significantly change the business case for automation.[258]

For example:

- The highly dense urban core of New York City's mesh distribution network, with its demand for reliable power, lends itself to distribution-automation systems.

[257] Schneider K. 2008. Communication between Kevin Schneider (PNNL) and Mark Weimar (PNNL), "Distribution Networks Among Utilities," November 4, 2008, Portland, Oregon.
[258] Moore and McDonnell 2007.

- The long rural feeders of West Virginia, which require hours of driving for electricity service provider linemen, are good candidates for remote monitoring and control.
- The well-connected network system and radially operated distribution grid of San Diego lends itself to automatic fault-detection and feeder-reconfiguration schemes.

In addition, there are significant differences in the vintages of the distribution system, primarily determined by economic growth in different regions of the country. Southwestern and southeastern regions have seen significant load growth in the last decades, which led to new T&D expansions with more modern technology. In contrast, established East Coast and Midwest cities tend to have dated system components that are a half-century old or more.

## A.11.4 Challenges

### A.11.4.1 Technical Challenges

Challenges in T&D automation for transmission differ from those for distribution. Methods for transmission-side automation are fairly well known, but deployment is challenged by funding and institutional barriers.[259] Distribution-side automation has seen an influx of new technologies, some of which are not very well understood. There are few existing options for modeling the effects of these new technologies on utilities, and, thus, the business case for these devices is more difficult to sell. Many operators, who traditionally have not had digital systems for managing their networks, are finding that the transition to automated T&D systems is expensive. This is because large-scale renovations are needed to install the prerequisite sensing and monitoring systems. Proving the value of these technologies through demonstration projects is an important first step toward gaining industry and regulatory acceptance. As with transmission automation, however, institutional barriers must be removed before high-level acceptance of this technology can foster widespread deployment.

Aging equipment and regulators' focus on benchmarks such as SAIDI and SAIFI, along with the need to reduce costs via automation, are beginning to bear fruit in the form of real cases of self-healing distributions systems. DONG Energy[260] in Denmark has turned to local control to reduce cost and communications needs in a local automated substation concept. The outcome is expected to be a reduction of outage time on automated feeders.

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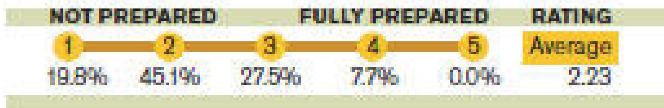
[259] EnergyBiz Magazine. 2006. *Guide & Sourcebook: Transmission & Distribution Automation*. January/February 2006, pp 51-66. Accessed October 28, 2008 at http://energycentral.fileburst.com/Sourcebooks/gsbk0106.pdf (undated webpage).

[260] Rasmussen KS. 2009. "A Real Case of Self Healing Distribution Network." In *Proceedings of the 20th International Conference on Electricity Distribution*. June 8-11, 2009, Prague. Accessed July 22, 2010 at http://www.neplan.ch/pdf/publications/Paper-Self-Healing-Distribution-Network.pdf (undated webpage).

Electricity service provider preparation for implementation of the smart grid relative to self-healing capabilities or remote operation in the United States will be necessary for utilities to operate efficiently, rapidly, with smaller workforces, and with fewer resources. Even with the focus on automation, preparation to reach important milestones has not been adequately completed according to a survey[261] performed by Energy Central's research arm, Sierra Energy Group. Of more than 90 IOUs surveyed, their answers demonstrate a marginal level of preparedness, as shown below in Figure A.25.

How close is your electricity service provider to having the grid be self-healing?




How close is your electricity service provider to being able to operate the distribution grid remotely?


**Figure A.25**. IOU Automation Preparedness Survey Responses (On a Five Point Scale)[262]

### A.11.4.2 Business and Financial Challenges

Deployment of new distribution-automation technology requires business-case analysis support for both the service provider and the regulator. While advanced tools now exist for technology-savvy providers, it is still difficult to model and justify these investments at a higher level. Standard business-case tools for utilities and regulators should be developed to expedite the analysis of these projects and the verification of their value.

Business-case tools are standards tools for vendors selling technology, but service providers are beginning to understand the need for "selling" technology advancement within their own organizations and to regulators. Technology road mapping is becoming a common tool to reach internal and external audiences. Providers or vendors that are using technology road mapping successfully to organize R&D efforts or implement smart grid strategies include the Bonneville

[261] Causey W. 2008. "The Pursuit of Automation." *Guidebook: Transmission & Distribution Automation*, January/February 2008. EnergyBiz. Accessed July 21, 2010 at http://energycentral.fileburst.com/Sourcebooks/gsbk0108.pdf (undated webpage).
[262] Causey 2008.

Power Administration (BPA),[263] Southern California Edison (SCE),[264] and GE.[265] A sample slide detailing the road mapping process[266] is shown below in Figure A.26.

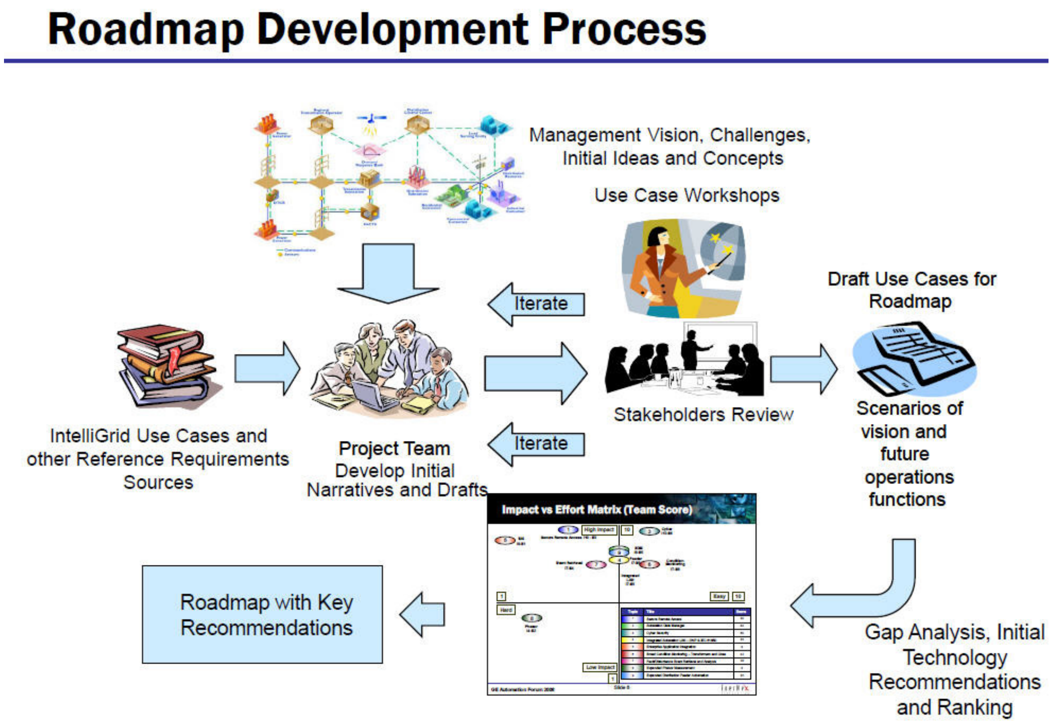



**Figure A.26**. Sample Technology Roadmap Development Process[267]

### A.11.5 Metric Recommendations

In future reports, the indicative metric should be reviewed against two types of metrics: the first consists of directly measurable or numeric estimates; the second set consists of qualitative elements. Qualitative metrics describe how automation components are used. A few metrics can be chosen from the many described below.

[263] BPA – Bonneville Power Administration. Undated. "Technology Roadmaps." *Technology Innovation.* Accessed July 22, 2010 at http://www.bpa.gov/corporate/business/innovation/ (undated webpage).

[264] SCE – Southern California Edison. 2010. *Southern California Edison Smart Grid Strategy & Roadmap*. Accessed July 22, 2010 at http://www.sce.com/NR/rdonlyres/BFA28A07-8643-4670-BD4B-215451A80C05/0/SCE_SmartGrid_Strategy_and_Roadmap.pdf (undated webpage).

[265] Berst J. August 4, 2009. "Behind-the-Scenes Look at GE's Smart Grid Strategy." *Smart Grid® News.com*. Accessed July 22, 2010 at http://www.smartgridnews.com/artman/publish/companies/Behind-the-Scenes_Look_at_GE_s_Smart_Grid_Strategy-663.html (last updated August 4, 2009).

[266] Farquharson R. 2009. "Smart Grid 101:Utility Applications and Roadmaps." Presented at the 2009 IEEE PES General Meeting. July 27, 2009, Calgary, Alberta. Accessed July 22, 2010 at http://www.ieee.org/organizations/pes/meetings/gm2009/slides/sg4-farquharson.pdf (undated webpage).

[267] Von Dollen D. 2007. *IntelliGrid Technology Transfer and Information Systems*. Electric Power Research Institute, Palo Alto, California. Accessed January 17, 2011 at http://intelligrid.epri.com/IntelliGrid_Project_Set_Calls/2009/P161A_Webcast_8.21.09/ps161a_webcast.pdf (undated webpage).

The quantitative metrics consist of an estimation of the rate of deployment of technology and automation, and the amount of investment for automation products to capture the economic activity.

- (11.a) Percentage of substations having automation (the metric used for this report)
- (11.b) Percentage of substations with outage detection
- (11.c) Percentage of circuits with fault-detection and -localization capabilities
- (11.d) Number of automated substations
- (11.e) Number of electromechanical relays
- (11.f) Number of microprocessor relays
- (11.g) Number of intelligent electronic devices IEDs deployed
- (11.h) Percentage of distribution circuits with automated (or remotely automated) sectionalization and reconfiguration capabilities
- (11.i) Percentage of distribution circuits with feeder load-balancing strategies

The investment metrics are defined as annual expenditures in dollars for:

- (11.j) Protective relays
- (11.k) Feeder/switch automation
- (11.l) Control-center upgrades
- (11.m) Substation measurement and automation
- (11.n) Distribution automation.

Based on Sheridan's scale for degree of automation, the following metrics are suggested:[268]

- (11.o) Operational T&D control action performed manually by linemen or operators in central control centers.
- (11.p) Distributed electronic and computing devices detect normal and fault conditions and offer a set of action options.
- (11.q) Intelligent electronic devices narrow the options down to a few, or suggest one. For instance, system fault localization and suggestions for fault isolation and feeder reconfiguration.

[268] Sheridan TB. 1992. *Telerobotics, Automation, and Human Supervisory Control*. MIT Press, Cambridge, Massachusetts.

- (11.r) IED recognizes a fault and executes a suggestion after operator/human approval. For instance, IEDs support an overarching control strategy that performs immediate remedial actions such as feeder reconfiguration and autonomous system restorations.
- (11.s) IED recognizes fault, then executes remedial actions automatically and informs the operator after execution.

Because of its qualitative nature, assigning an appropriate scale to the degree of automation for any particular segment of the grid requires a judgment call. To assess the level of automation deployment it is recommended to use a set of quantitative metrics that capture a) the level of adoption of automation technology, and b) the level of investment as indicator of a rate of change in the penetration of automation in the U.S. grid. Furthermore, a qualitative metric that describes the level of control autonomy of the automation products and the degree to which automation strategies can be executed without human interventions or interactions should be considered.

The metrics are only useful if data exist or can be collected at a cost low enough to allow tracking of the metrics over time. For this particular T&D automation assessment, we interviewed 24 service providers to collect a representative sampling of the data. In the future, the Edison Electric Institute (EEI) could function as an intermediary to the investor-owned companies; for the publicly owned entities, the Public Power Association could be consulted as a potential intermediary for collecting data from the over 3,000 public T&D organizations. Gathering this data would require an ongoing effort, but would provide valuable information on the progress of T&D automation. Note that progress in this area is difficult to accurately assess with respect to improvements over time. The total number of substations or total industry output figures for T&D automation products is only a crude indicator of the technological progress that will certainly continue into the coming decades.

DOE's Smart Grid Investment Program[269] (SGIP) is in the process of spending $3.4 billion plus an equal or greater amount from collaborators. The awards have been made and there will be detailed data collected on the technologies, business cases, costs, and deployment scenarios. Data on the types of information suggested above on numbers of devices installed and/or dollar spending on those devices will be collected and made available on DOE's website.

[269] DOE – U.S. Department of Energy. 2010. "Recovery Act Selections for Smart Grid Investment Grant Awards – by Category." U.S. Department of Energy, Washington, D.C. Accessed July 22, 2010 at http://www.energy.gov/recovery/smartgrid_maps/SGIGSelections_Category.pdf (undated webpage).

# A.12 Metric #12: Advanced Meters

## A.12.1 Introduction and Background

A major element of smart grid implementation projects continues to be advanced meters and their supporting infrastructure, or AMI, with ever-increasing numbers of electric service providers completing pilot programs and moving toward full AMI deployment. ARRA, in 2009, allocated $3.4 billion in grants to invest in smart grid technologies and electric transmission infrastructure with total investment of $8.2 billion.[270] For this report, the FERC Demand Response Assessment definition of AMI has been adopted: "Advanced metering is a metering system that records customer consumption [and possibly other parameters] hourly or more frequently and that provides for daily or more frequent transmittal of measurements over a communication network to a central collection point." [271]

Smart grid system implementation relies on a variety of AMI technologies that provide two-way communication between the customer and the electric service retailer. Figure A.27 illustrates the flow of metering data between the consumer Home Area Network (HAN), AMI technologies such as smart meters or gateways, and information technology (IT) systems. HAN communications access AMI data and can also serve as the gateway from the service provider to the meter. This communication system can operate though wired, wireless, open or proprietary networks, and supply/communicate a variety of consumer and electricity service provider applications such as energy awareness, demand response, and distributed generation.

[270] DOE – U.S. Department of Energy. October 27, 2009. "President Obama Announces $3.4 Billion Investment to Spur Transition to Smart Energy Grid." U.S. Department of Energy, Washington, D.C. Accessed June 14, 2010 at http://www.energy.gov/news2009/8216.htm (last updated October 27, 2009).

[271] FERC – Federal Energy Regulatory Commission. 2006. *Assessment of Demand Response and Advanced Metering.* Staff Report, Docket Number AD-06-2-000, August 2006. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 22, 2010 at http://www.ferc.gov/legal/staff-reports/demand-response.pdf (undated webpage).

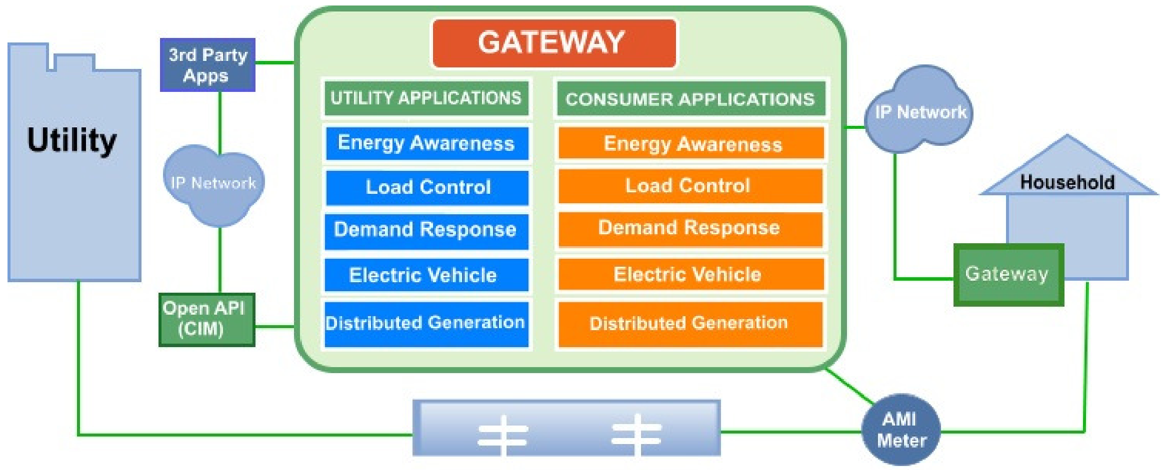



**Figure A.27**. Overview of AMI Interface[272]

AMI technologies enable the communication of real-time pricing data, grid conditions, and consumption information. When smart meters are coupled with other enabling technology, such as programmable communicating thermostats and data management systems, information can be gathered and monitored by both the service provider and the consumer. Such data can enable demand response, dynamic pricing, and load management programs.

Capabilities of AMI that benefit both consumers and electric retailers include dynamic pricing and demand response. The reduced peak-capacity requirement from dynamic pricing lowers peak demand, reduces generation costs and improves overall system reliability.[273] Closely related to dynamic pricing, "demand response" refers to changes in energy consumption by end-users in response to electricity costs that vary over time, to incentives from energy providers, or when system reliability is jeopardized.[274] Implementation of AMI technologies allows full realization of advanced smart grid systems through the following:

- automatically adjusting energy prices in peak hours or situations (dynamic pricing)
- allowing customers to manually respond to dynamic pricing by adjusting thermostats or changing peak-consumption patterns
- allowing customers to automatically respond to dynamic pricing through automated technology, such as a programmable communicating thermostat and smart appliances

[272] Adapted from the Tendril Platform at http://www.tendrilinc.com/platform.
[273] Faruqui A, S Sergici, and L Wood. 2009. *Moving Toward Utility-Scale Deployment of Dynamic Pricing in Mass Markets.* IEE Whitepaper, Institute for Electric Efficiency, Washington, D.C. Accessed June 15, 2010 at http://www.electric-efficiency.com/reports/IEE_Utility-ScaleDynamicPricing_0609.pdf (undated webpage).
[274] FERC – Federal Energy Regulatory Commission. 2009a. *A National Assessment of Demand Response Potential.* Staff Report, June 2009. Prepared by The Brattle Group; Freeman, Sullivan & Co.; and Global Energy Partners, LLC for the Federal Energy Regulatory Commission, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf (undated webpage).

- DLC by utilities
- interruptible tariffs
- backup generation
- permanent load shifting
- supporting EVs and PHEVs.[275]

In addition to the preceding system benefits, companies are reporting results from pilot programs and associated cost-benefit analyses. One company, CL&P, has reported base-scenario results established on average meter costs, meter life, dynamic pricing models, forward capacity, and conservation. The analysis showed a positive net benefit of $87 million, or a benefit-cost ratio of 1.18.[276] A pilot program conducted by Southern California Edison in 2008 reflected a positive net benefit of $116 million, or a benefit-cost ratio of 1.06.[277]

Similar pilot programs have been completed or are in process by Pepco's PowerCentsDC™, Portland General Electric, Allegheny Power, and Commonwealth Edison.[278] In late 2009, Con Edison invested $6 million in an 18-month pilot program designed to measure integration of AMI technology in New York City.[279]

### A.12.2 Description of the Metric and Measurable Elements

The following two measurements have been identified as important for understanding and quantifying advanced metering. Meters will have to meet the minimum qualifications set by FERC to be counted in these measurements.

*(Metric 12.a) Number of meters planned or installed*—tracking this number across states and regions will allow the United States to establish a baseline and a growth model for advanced-meter penetration.

*(Metric 12.b) Percentage of total demand served by AMI customers*—knowing the percentage of the grid's load served by AMI technology will enable system operators to better manage load and deploy demand-response measures.

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[275] FERC 2009a.

[276] CL&P – Connecticut Light & Power. 2010. *CL&P AMI and Dynamic Pricing Deployment Cost Benefit Analysis*. Docket Number 05-10-03RE01, Compliance Order No. 4. Accessed June 15, 2010 at http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/recommendations/$File/recommendations.pdf (undated webpage).

[277] Faruqui et al. 2009.

[278] FERC 2009°.

[279] *ConEdison.* August 4, 2009. "Con Edison Launches Smart Grid Pilot Program in Queens." Press Release. Accessed June 15, 2010 at http://investor.conedison.com/phoenix.zhtml?c=61493&p=irol-newsArticle&ID=1316617&highlight (last updated August 4, 2009).

### A.12.3 Deployment Trends and Projections

Current estimates of AMI meter penetration include 7.95 million meters installed nationwide in 2009.[280] Projections for future installation of AMI range from a partial-deployment figure of 80 million meters installed by 2019, to 141 million under a full-deployment scenario.[281] Independent analyses of AMI penetration indicate deployments nationwide have expanded to an estimated 16 million in 2010, representing 10.7 percent of U.S. electric meters (Figure A.28).[282,283] State public electricity service provider commissions have approved an additional 34 million AMI deployments. Installed and approved AMI deployments identified by EMeter[284] are presented in Table A.15.

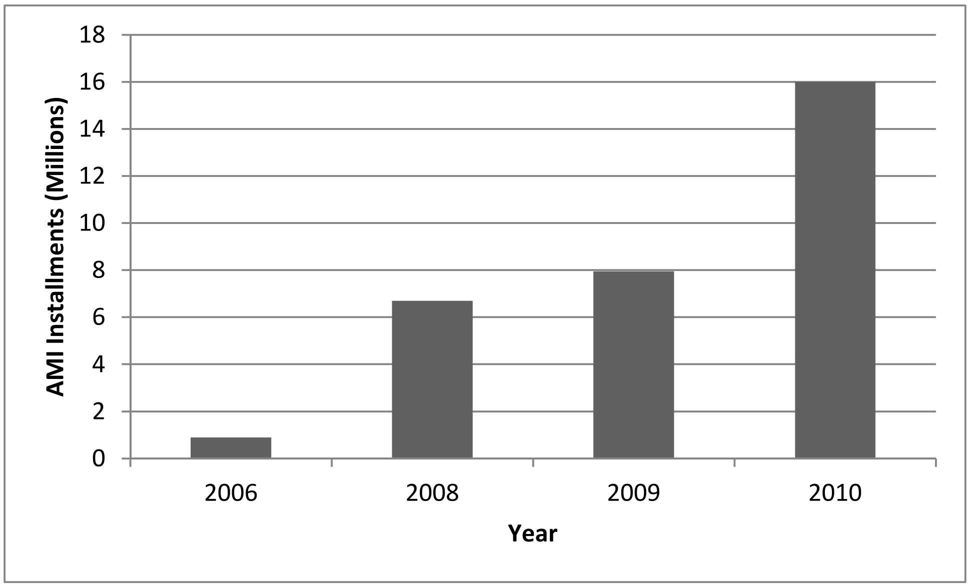


**Figure A.28**. AMI Installments

[280] FERC – Federal Energy Regulatory Commission. 2009b. *Assessment of Demand Response and Advanced Metering.* Staff Report, September 2009. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 8, 2010 at http://www.ferc.gov/legal/staff-reports/sep-09-demand-response.pdf (undated webpage).

[281] FERC 2009b.

[282] Neichin G and D Cheng. 2010. *2010 U.S. Smart Grid Vendor Ecosystem: Report on the Companies and Market Dynamics Shaping the Current U.S. Smart Grid Landscape*. Cleantech Group LLC. Accessed September 29, 2010 at http://www.energy.gov/news/documents/Smart-Grid-Vendor.pdf (undated webpage).

[283] King C. 2010. Email from Chris King (EMeter Corporation) to Patrick Balducci (Pacific Northwest National Laboratory), "Secretary Chu Off By 14 Million Smart Meters," September 1, 2010, Portland, Oregon.

[284] King 2010.

**Table A.15**. Installed and Planned Smart Meters (millions)

| Installed AMI | | Approved AMI | |
|---|---|---|---|
| Electricity Service Provider | # AMI Units | Electricity Service Provider | # AMI Units |
| AEP TX | 0.1 M | AEP TX | 0.9 M |
| Alliant | 0.5 M | Alliant | 0.9 M |
| CenterPoint | 0.5 M | CenterPoint | 1.9 M |
| Delmarva | 0.2 M | Delmarva | 0.2 M |
| Exelon | 0.2 M | Exelon | 2.0 M |
| FPL | 0.6 M | FPL | 3.9 M |
| Idaho Power | 0.1 M | Idaho Power | 0.4 M |
| Oncor | 1.3 M | Oncor | 1.7 M |
| PG&E | 6.5 M | PG&E | 3.6 M |
| SDG&E | 1.4 M | SDG&E | 1.1 M |
| Southern Company | 1.0 M | Southern Company | 3.6 M |
| PPL | 1.4 M | BGE | 2.0 M |
| SCE | 1.4 M | Bluebonnet | 0.1 M |
| PGE | 0.8 M | Burbank Water & Power | 0.1 M |
| AEP OH | 0.2 M | CPS Energy | 1.0 M |
| | | Pepco | 0.8 M |
| | | SCE | 3.6 M |
| | | SCG | 6.0 M |
| | | Silicon Valley Power | 0.1 M |
| | | TNMP | 0.2 M |
| | | Westar Energy | 0.1 M |
| Total | 16.5 M | Total | 34.2 M |

Federal grant awards for AMI implementation under ARRA total $812.6 million to date.[285] States with the most significant AMI investment under ARRA include Arizona, Maine, Maryland, and Texas, but projects are being undertaken by numerous service companies in 19 states, with additional laws or policies passed in Hawaii, Massachusetts, and Pennsylvania.[286] Table A.16 shows total ARRA award funds, total project value, electricity service provider, and location. AMI implementation projects range from smart-meter installation, two-way communications, dynamic pricing, and data management technologies.

[285] DOE – U.S. Department of Energy. 2010. "Recovery Act Selections for Smart Grid Investment Grant Awards – by Category." U.S. Department of Energy, Washington, D.C. Accessed June 14, 2010 at www.energy.gov/media/SGIGSelections_Category.pdf (undated webpage).
[286] FERC 2009a.

**Table A.16**. Recovery Act Selections for Smart Grid Investment Grant Awards—Category 1: Advanced Metering Infrastructure[287]

| ARRA Selections For Smart Grid Investment Grant Awards - By Category: AMI Infrastructure | | | |
|---|---|---|---|
| Name of Awardee | Funding Award | Total Project Value | Location |
| CenterPoint Energy | $200,000,000 | $639,187,435 | Houston, TX |
| Baltimore Gas and Electric | $200,000,000 | $451,814,234 | Baltimore, MD |
| Central Maine Power | $95,858,307 | $191,716,614 | Augusta, ME |
| Salt River Project | $56,859,359 | $114,003,719 | Tempe, AZ |
| Reliant Energy Retail, LLC | $19,839,689 | $63,696,548 | Houston, TX |
| Cleco Power LLC | $20,000,000 | $69,026,089 | Pineville, LA |
| South Mississippi Electric | $30,563,976 | $61,318,005 | Hattiesburg, MS |
| San Diego Gas and Electric | $28,115,052 | $59,427,645 | San Diego, CA |
| City of Glendale Water & Power | $20,000,000 | $51,302,105 | Glendale, CA |
| Lakeland Electric | $14,850,000 | $35,078,152 | Lakeland, FL |
| Denton County Electric | $17,205,844 | $40,966,296 | Corinth, TX |
| Pacific NW Generating | $19,577,326 | $39,153,486 | Portland, OR |
| Cobb Electric Membership Corp. | $16,893,836 | $33,787,672 | Marietta, GA |
| South Kentucky Rural Electric | $9,538,234 | $19,636,215 | Somerset, KY |
| Connecticut Municipal Electric | $9,188,050 | $18,376,100 | Norwich, CT |
| Talquin Electric Cooperative | $8,100,000 | $16,200,000 | Quincy, FL |
| Black Hills/Colorado Electric | $6,142,854 | $12,285,708 | Pueblo, CO |
| Black Hills Power, Inc. | $9,576,628 | $19,153,256 | Rapid City, SD |
| City of Westerville, OH | $4,320,000 | $10,663,000 | Westerville, OH |
| Cheyenne Light, Fuel & Power | $5,033,441 | $10,066,882 | Cheyenne, WY |
| Entergy New Orleans, Inc. | $4,996,968 | $9,993,936 | New Orleans, LA |
| Navajo Tribal Utility Association | $4,991,750 | $10,611,849 | Ft. Defiance, AZ |
| Sioux Valley SW Electric | $4,016,368 | $8,032,736 | Coleman, SD |
| Woodruff Electric | $2,357,520 | $5,016,000 | Forrest City, AR |
| City of Quincy, FL | $2,471,041 | $4,942,082 | Quincy, FL |
| ALLETE, Inc. | $1,544,004 | $3,088,008 | Duluth, MN |
| City of Fulton | $1,527,641 | $3,055,282 | Fulton, MO |
| Marblehead Municipal Light | $1,346,175 | $2,692,350 | Marblehead, MA |
| Tri-State Electric | $1,138,060 | $2,428,454 | McCaysville, GA |
| Wellsboro Electric | $431,625 | $961,195 | Wellsboro, PA |
| Stanton County Public Power | $397,000 | $794,000 | Stanton, NE |
| Total | $816,880,748 | $2,008,475,053 | |

[287] DOE 2010.

In summary, the number of advanced meters meeting the requirements of Metric 12a grew from approximately 0.9 million (0.7 percent of all residential meters) in 2006, to 6.7 million meters in 2008, 7.95 million in 2009,[288] and 16 million in 2010.[289,290] Given that there are approximately 150 million electricity meters,[291] we estimate that roughly 10.7 percent of load is presently served by advanced metering.

#### A.12.3.1 Stakeholder Influences

Stakeholders in advanced metering include

- distribution-service providers, to install and recover the investment in advanced meters
- products and services suppliers including IT and communications, to supply the appropriate technology for deployment and use of advanced meters
- local, state, and federal energy policymakers – local regulators will be needed to ensure that distribution-service providers recover their investments in advanced meters
- residential consumers – when AMI is coupled with dynamic pricing, customers will have more control of their energy consumption and will be able to effectively monitor their electric bills
- the financial community – numbers vary for how much it will cost to successfully deploy AMI technology, but it is likely to reach several billion dollars; for example, Duke Energy has allocated $1 billion over the next five years for digital and automated technology deployment in Indiana, Kentucky, North Carolina, Ohio, and South Carolina.[292]

#### A.12.3.2 Regional Influences

In 2008, states in the Mid-Atlantic, Florida and Midwest regions had the highest penetration rates (approximately 5 to 10 percent) and the remaining regions had lower-than-average reported rates.

Since 2009, AMI pilots or full-deployment programs have been announced by 26 electric service retailers in 19 states.[293] Table A.17 contains a selection of recent data regarding specific regional electricity service provider investment in AMI technologies by service area and project type.

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[288] FERC 2009b.
[289] Neichin and Cheng 2010.
[290] King 2010.
[291] King 2010.
[292] Scanzoni D. 2010. Email to David Scanzoni (Duke Energy Corporate Communications) from Chrissi Antonopoulos (Pacific Northwest National Laboratory), "Duke Energy Smart Meter Data," June 15, 2010, Portland, Oregon.
[293] FERC 2009b.

**Table A.17**. Various Electricity Service Provider Investments in AMI

| Electricity Service Provider | State | Project Description & Investment |
|---|---|---|
| American Electric Power (AEP) | AR, IN, KY, LA, MI, OH, OK, TN, TX, VA WV | Deployment of 5 million AMI meters by 2015 in GridSmart Program. Investment of $395 million in OH, OK and TX.[294] |
| Southern Company | GA, AL, FL, MS | Company has matched the $165 million government stimulus grant to expand two-way communication and self-healing technologies of AMI.[295] |
| Duke Energy | OH, NC, SC, KY | 200,000 meters installed by June 2010. $1 billion investment over the next five years.[296] |
| PG&E | CA | 5.8 million gas and electric meters installed by June 2010. Full deployment by 2012. Total investment for upgrades is $466 million.[297] |
| Southern California Edison | CA | Aims to install 5 million meters by 2012. Requested $1.3 billion for project.[298] |
| Oncor | TX | 1 million meters installed in June 2010. Aims to install 3 million by 2012. $532 million in capital costs for meter installation.[299] |
| DTE Energy | MI | 700,000 smart meters and 5,000 high tech thermostats installed in 2010. Company has matched $84 million government stimulus grant.[300] |
| Alliant Energy | MI, IA, MN | 1.1 million electric smart meters and 400,000 gas meters installed by 2010. $200 million company investment.[301] |

[294] AEP – American Electric Power. 2010. *A Climate of Change: Our Progress, Our Future*. Accessed June 15, 2010 at http://www.nxtbook.com/nxtbooks/aep/accountability2010/#/2 (undated webpage).

[295] Southern Company. October 27, 2009. "Southern Company Awarded $165 Million to Advance Smart Grid Initiatives." Press Release. Accessed June 17, 2010 at http://southerncompany.mediaroom.com/index.php?s=43&item=1992 (last updated October 27, 2009).

[296] Scanzoni 2010.

[297] CPUC – California Public Utilities Commission. March 12, 2009. "CPUC Authorizes PG&E to Upgrade Its Smart Meter Program." Accessed June 15, 2010 at http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/98459.htm (last updated March 12, 2009).

[298] SCE – Southern California Edison. Undated. "Edison's Smarter Meter." *Southern California Edison Backgrounder*. Accessed June 15, 2010 at http://www.sce.com/NR/rdonlyres/4BDCBE35-697E-49C6-9773-C49A019E6FD3/0/SCEsSmarterMeter.pdf (undated webpage).

[299] Cuellar C. 2010. Email Message from Catherine Cuellar (Oncor Communications) to Chrissi Antonopoulos (Pacific Northwest National Laboratory Intern), "AMS Overview For B. Solomons V.2PPT," June 16, 2010, Portland, Oregon.

[300] DTE Energy. October 27, 2009. "DTE Energy SmartCurrents Program Awarded $84 Million DOE Grant." News Release. Accessed June 17, 2010 at http://dteenergy.mediaroom.com/index.php?s=43&item=453 (last updated October 27, 2009).

[301] Alliant Energy. Undated. *Smart Grid: Building a Smart Energy Future for Our Customers and Our Communities*. Accessed June 16, 2010 at http://www.alliantenergy.com/UtilityServices/CustomerService/MeterReading/016361 (undated webpage).

## A.12.4 Challenges

AMI manufacturers and designers face a myriad of demands from electricity service provider companies and the consumers they represent. Subjects such as weatherproofing, maintenance schedules, and memory and data storage all need to be addressed in addition to the development of and adherence to national and state standards for design, communication, and more. These challenges are discussed below.

### A.12.4.1 Technical Challenges

There are a variety of technical considerations involving advanced meters. FERC identifies the primary technical barriers as: lack of smart-meter infrastructure, high cost of some enabling technologies, and lack of interoperability and open standards.[302] Although a uniform understanding of minimum qualifications for AMI technology exists, many service providers will find any number of additional qualifications and functions necessary to effectively serve their clients. As each provider or region has different challenges, including additional "minimum" features or "standard features," AMI systems may prove to be redundant, less cost effective, or even useless in some cases. Such challenges will be faced by providers that install smart meters that are not designed to be integrated with other AMI systems. Additionally, there may be different opinions between regions on what qualifies as a specific function. For example, PG&E's definition of "tamper flagging capability" may be significantly different from that of CL&P. Other considerations such as battery backup, network structure, communication protocols, and encryption also pose technical challenges.

### A.12.4.2 Business and Financial Challenges

Primary challenges to AMI advancement can be assessed by looking at deployment scenario variations and cost-benefit analysis, equipment/labor costs, and existing operational technologies. Primary business challenges include:

Deployment Scenario Variations and Cost-Benefit Analysis: As AMI technologies continue to be evaluated by utilities, varying assumptions based on deployment scenarios (business-as-usual [BAU], expanded BAU, achievable participation, and full participation) significantly alter estimations of costs and benefits. Furthermore, in order for AMI technology to be fully beneficial, it must be coupled with pricing programs and other enabling technology.[303] Long-term maintenance costs of the new technologies are unknown, as are costs associated with customer complaints or troubleshooting.

[302] FERC 2009b.
[303] FERC 2009b.

Equipment and Labor Costs: Although ARRA allocated billions of dollars to smart grid technology, there are still significant up-front costs to implement AMI. These include system hardware, software, and labor costs associated with deployment and installation of new meters, customer education, and IT system integration.[304] One estimation forecasts smart meter implementation to cost as much as $40 billion.[305] These costs could increase due to differing regional requirements for AMI system features.

Existing Operational Technologies: AMI technology should not be confused with automated meter reading (AMR) technology, which focuses on drive-by and walk-by meter-reading solutions and does not typically use fixed networks. Drive- or walk-by meters (i.e., AMR) have existed for some time and are "…possibly discouraging the installation of the more demand-response friendly AMI."[306]

### A.12.5 Metric Recommendations

Good, reportable data have not yet been found for Metric 12b concerning the fraction of load served by AMI. It is recommended that further research be conducted to locate or determine this value.

[304] Faruqui et al. 2009.

[305] Faruqui A and S Sergici. 2009. *Household Response to Dynamic Pricing of Electricity—A Survey of the Experimental Evidence.* Accessed June 17, 2010 at http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf (undated webpage).

[306] FERC – Federal Energy Regulatory Commission. 2007. *Assessment of Demand Response & Advanced Metering 2007*. Staff Report, September 2007. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 26, 2010 at http://www.ferc.gov/legal/staff-reports/09-07-demand-response.pdf (undated webpage).

# A.13 Metric #13: Advanced Measurement Systems

## A.13.1 Introduction and Background

For all practical purposes, the term Advanced Measurement Systems is presently synonymous with Wide Area Measurements Systems. This may not always be the case, but has been so since it was recognized that precise timing signals from global positioning system (GPS) satellites could be used for accurately synchronized power system measurements from all parts of the networked power system. A Wide Area Measurement System (WAMS) uses such measurements in the grid management process. A WAMS typically samples the waveforms of voltages and currents 30 times per second, and from this information calculates the state of the power network. These calculations, using information networked across the power system, can give operators a degree of "situational awareness" that is not otherwise available.[307]

Just as Advanced Measurement System is synonymous with Wide Area Measurement, Wide Area Measurement is synonymous with Phasor Measurement. Enabled by faster sampling and accurate timing, Phasor Measurement Units (PMUs) give a picture of the power system that has not been previously possible.

WAMS/PMUs represent a step change in the knowledge of the power system for two reasons. First, the sampling is fast, and that speed allows phasor quantities to be observed. Before WAMS, power system parameters were averaged, and measured approximately every 4 seconds. Second, the networking of observed phasor quantities allows calculations of other quantities, especially some that are not directly observable. In particular, a WAMS system can compute what is called the power angle, the phasor angle between one area and another. From this quantity, the power flowing from one region to another can be gauged without knowing exactly which power lines are carrying it. That is a very useful feature when lines are tripping and a blackout is about to begin.

A benefit of this kind of measurement system is that the data are combined across a large area to give a view of the overall power system operation. Due to the variety of benefits presented by WAMS, it is expected that such technologies will eventually be present in most grid control systems.[308]

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[307] Hauer JF and JG DeSteese. 2007. *Descriptive Model of a Generic WAMS.* PNNL-17138, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 16, 2008 at http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17138.pdf (undated webpage).

[308] Hadley MD, JB McBride, TW Edgar, LR O'Neil, and JD Johnson. 2007. *Securing Wide Area Measurement Systems*. PNNL-17116, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 25, 2010 at http://www.oe.energy.gov/DocumentsandMedia/Securing_WAMS.pdf (undated webpage).

At the present time, the parts that constitute the WAMS method of measurement are being more widely applied. With DOE support, the standard (IEEE Std. C37.118) that governs their use is under active revision to facilitate the process.

- WAMS has evolved over the past two decades to provide the following functions:[309]
- real-time observation of system performance
- early detection of system problems
- real-time determination of transmission capacities
- analysis of system behavior, especially major disturbances
- special tests and measurements, for purposes such as
  - special investigation of system dynamic performance
  - validation and refinement of planning models
  - commissioning or re-certification of major control systems
  - calibration and refinement of measurement facilities
- refinement of planning, operation, and control processes essential to best use of transmission assets.

### A.13.2 Description of Metric and Measurable Elements

The measurable element for this metric is

*(Metric 13) The total number of advanced measurement devices*—the total number of measurement devices that are networked and are providing useful information at the transmission and distribution levels.

### A.13.3 Deployment Trends and Projections

There is no single authority keeping track of the deployment of PMUs. Therefore, the trends and projections given here necessarily come from several sources. Further, because there can be many possible applications for the WAMS installations, it is hard to estimate how many may be needed. It is, therefore, hard to say either how many there are at present, or how many will ultimately be needed. Most likely, the situation will resemble the deployment of the copying machine, with growth that continues because new applications are realized.

[309] Hauer JF, WA Mittelstadt, KE Martin, JW Burns, and H Lee. 2006. "Best Practices to Improve Power System Dynamic Performance and Reduce Risk of Cascading Blackouts: Monitoring of System Dynamic Performance." IEEE Power Engineering Society Task Force on Best Practices to Minimize Blackout Risk. IEEE Power Engineering Society, New York.

A NERC technical committee report indicated that at least 500 phasor measurement units would be required to adequately monitor the U.S. grid.[310] A study completed by Northeastern University calculates more will be needed; it indicated that between 721 and 1300 PMUs would be necessary just to address a complete set of applications envisioned for the Entergy network, a power system that covers parts of five southern states.[311]

The number of installed and networked PMUs has been increasing steadily in the past few years. NASPI documented 140 networked PMUs installed in the U.S. in 2009. In 2010, the number increased to 166 PMUs. ARRA investment is expected to produce a six fold increase in networked PMUs by 2014, with networked PMUs reaching 1,043.[312] Figure A.29 illustrates the growth of PMU installations over time, using numbers from sources quoted above. The large jump in PMU installations by 2014 is due to ARRA stimulus spending.

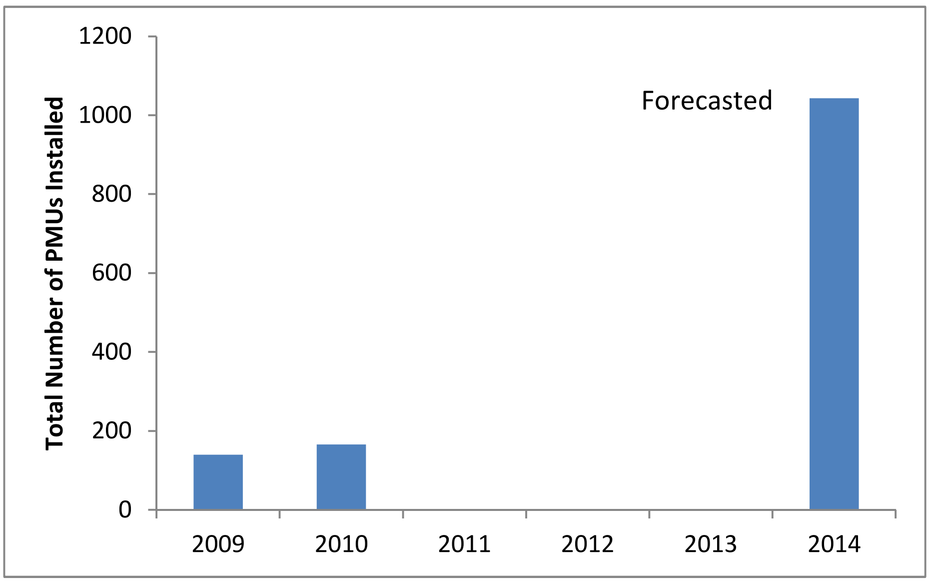


**Figure A.29**. PMU Installations Current and Estimated

In June 2010, the NASPI work group meeting assessed the status of "Advanced Synchrophasor Research," and the following projects were identified as being in process:[313]

310 NERC – North American Electric Reliability Corporation. 2007. *Technology Committee May 1, 2007 Minutes*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed September 4, 2008 at http://www.nerc.com/docs/bot/bottc/TC_0507m_Draft.pdf (undated webpage).

311 NERC 2007.

312 Overholt P. 2010a. "North American SynchroPhasor Initiative (NASPI) and DOE's Smart Grid Investment Grants," slide #10. Presented at the EEI Transmission, Distribution and Metering Conference. April 11-14, 2010, Arlington, Virginia. Accessed October 8, 2010 at http://www.eei.org/meetings/Meeting%20Documents/2010-04-TDM-Tuesday-4-Overholt-Philip.pdf (undated webpage).

313 Overholt P. 2010b. "North American SynchroPhasor Initiative: DOE Update." Presented at the NASPI Work Group Meeting. June 8-9, 2010, Vancouver, British Columbia. Accessed October 25, 2010 at http://www.naspi.org/meetings/workgroup/2010_june/presentations/session_01/overholt_doe_naspi_update_20100608.pdf (undated webpage).

- Synchrophasor-based Adaptive Relaying Project—University of California
- Synchrophasor-based Three-phase Tracking State Estimator for Unbalanced Conditions and Adaptive Islanding—Virginia Polytechnic Institute and State University
- Real-time Implementation of the Distributed Dynamic State Estimation for On-line Generator Parameter Identification and Wide-area Transient Stability Analysis—Georgia Tech Research Corporation
- Wide-area, Real-time Visualization of Frequency, Voltage and Current Contours for Security Monitoring, On-line Identification of Major Events and Event "Instant" Replay—Electric Power Research Institute
- Power Grid Reliability and Security Project (which includes analysis and simulation for a secure communication network from PMU to synchrophasor applications)—Washington State University.

#### A.13.3.1 Associated Stakeholders

Advanced measurement systems primarily affect transmission providers, distribution service providers, and end-users, but others will also be affected, including reliability coordinators, and products and services suppliers. In more detail, stakeholders are impacted as follows:

- Transmission providers will assist in the need to understand the business case for deploying advanced measurement technology and properly quantify the benefits of this technology to enhance the reliability of the power system.
- Reliability coordinators and NERC have roles in ensuring grid reliability. They will also need to understand the business case for deployment of the advanced measurement systems.
- Distribution service providers will benefit from better customer relations associated with the enhanced grid reliability.
- End users (residential, commercial, and industrial) have a stake in anything that could affect power system reliability.
- Products and services suppliers have two roles. First, they can help educate the industry about the need for advanced systems. Second, they must continue development of the technology and expand useful applications.
- Local, state, and federal energy policymakers all have a stake in ensuring the reliability of the grid, which has been a significant force behind the U.S. economic engine.

### A.13.3.2 Regional Influences

While the basic technology is being deployed throughout the world,[314] there are important regional differences that drive the applications that are sought from advanced measurement technologies. Measuring interregional electromechanical oscillations fueled the early development of WAMS. First appearing in the Western Interconnection in the early 1970s when the northwest region was connected to California through the Pacific Intertie transmission projects, these oscillations were a continuing source of reliability concern. They were an instability that could be seen in the power flows during the system blackout of August 10, 1996.

Even the limited data from the then-available WAMS was useful in the investigation of the 1996 blackout and stimulated further development. This development is a collective response to the shared needs for measurement-based information.[315,316]

Under DOE's Smart Grid Investment Grant program, the WECC Western Interconnection Synchrophasor Program[317] intends to deploy 250 to 300 PMUs, using a private wide-area network backbone for communications to Phasor Data Concentrators. The purpose of the WISP project is to use synchrophasor technology to enable smart grid functionality in the WECC. The WISP project will include real-time and off-line applications for the following functions: situational awareness, system performance analysis, model validation, real-time control, and protection and system restoration functionality.

The second major region of the U.S. power grid is the Eastern Interconnection. Here, data from PMUs were instrumental in the investigation of the August 14, 2003, blackout that affected large portions of the northeastern United States and Canada. Significantly, the blackout investigation report cited lack of situational awareness as one of the root causes that contributed to the blackout. Situational awareness is a capability that is enhanced by WAMS data and applications.

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[314] Chakrabarti S, E Kyriakides, T Bi, D Cai, and V Terzija. 2009. "Measurements Get Together." *IEEE Power & Energy Magazine* 7(1):41-49. Accessed October 25, 2010 at http://eprints.qut.edu.au/17746/1/17746.pdf (undated webpage).

[315] WSCC – Western States Coordinating Council. 1990. *Evaluation of Low Frequency System Response: Study Results and Recommendations*. Report of the WSCC 0.7 Hz Oscillation Ad Hoc Work Group to the WSCC Technical Studies Subcommittee, September 1990.

[316] Hauer JF and JR Hunt. 1996. "Extending the Realism of Planning Models for the Western North American Power System." In *Proceedings of the V Symposium of Specialists in Electric Operational and Expansion Planning (SEPOPE)*. May 19-24, 1996, Recife, PE, Brazil. In association with the WSCC System Oscillations Work Groups.

[317] VanZandt V and M Bianco. 2010. "The Western Interconnection Synchrophasor Program (WISP): Smart Grid Investment Grant." Presented at the NASPI Working Group Meeting. February 24-25, 2010, Austin, Texas. Accessed October 25, 2010 at http://www.naspi.org/meetings/workgroup/2010_february/presentations/wednesday_am/vanzandt_wecc_sgigawardee_20100224.pdf (undated webpage).

For example, after Hurricane Gustav struck the Gulf Coast in September 2008, a section of the power system became separated. It remained separated for a period of 33 hours. Entergy Corporation used its synchrophasor measurements and analytical tools to manage both system separation and islanding, and, later, system restoration.[318] The experience showed that PMUs were vital in identifying and warning of islanding conditions, and provided insight into managing a power island.[319] At the national level, NASPI is a joint DOE and NERC program to help facilitate the deployment of time-synchronized measurements, including particularly PMUs, throughout North America. NASPI's mission is to improve power system reliability and visibility through wide area management and control. The effort is closely coordinated with industry.[320,321]

Figure A.30 shows, as of September 2009, the existing and planned PMU deployment locations in North America. There are many PMUs installed that are not networked, across organizations not shown on the map, with many more projected in the future.

[318] NASPI – North American SynchroPhasor Initiative. 2009. *Synchrophasor System Benefits Fact Sheet*. Accessed October 7, 2010 at http://www.naspi.org/resources/2009_march/phasorfactsheet.pdf (undated webpage).

[319] Galvan F and CH Wells. 2010. "Detecting and Managing the Electrical Island Created in the Aftermath of Hurricane Gustav Using Phasor Measurement Units (PMUs)." In *Proceedings of the 2010 IEEE PES Transmission and Distribution Conference and Exposition*. April 19-22, 2010, New Orleans, Louisiana. Accessed October 25, 2010 at http://ieeexplore.ieee.org/xpls/abs_all.jsp?arnumber=5484197 (undated webpage).

[320] Dagle JF. 2008. "North American SynchroPhasor Initiative." In *Proceedings of the 41st Hawaii International Conference on System Sciences*. January 7-10, 2008, Waikoloa, Hawaii. Accessed November 24, 2008 at http://ieeexplore.ieee.org/stamp/stamp.jsp?arnumber=4438868&isnumber=4438696 (undated webpage).

[321] NASPI – North American SynchroPhasor Initiative. 2008. *North American SynchroPhasor Initiative*. Accessed November 24, 2008 at http://www.naspi.org/ (last updated October 2010).

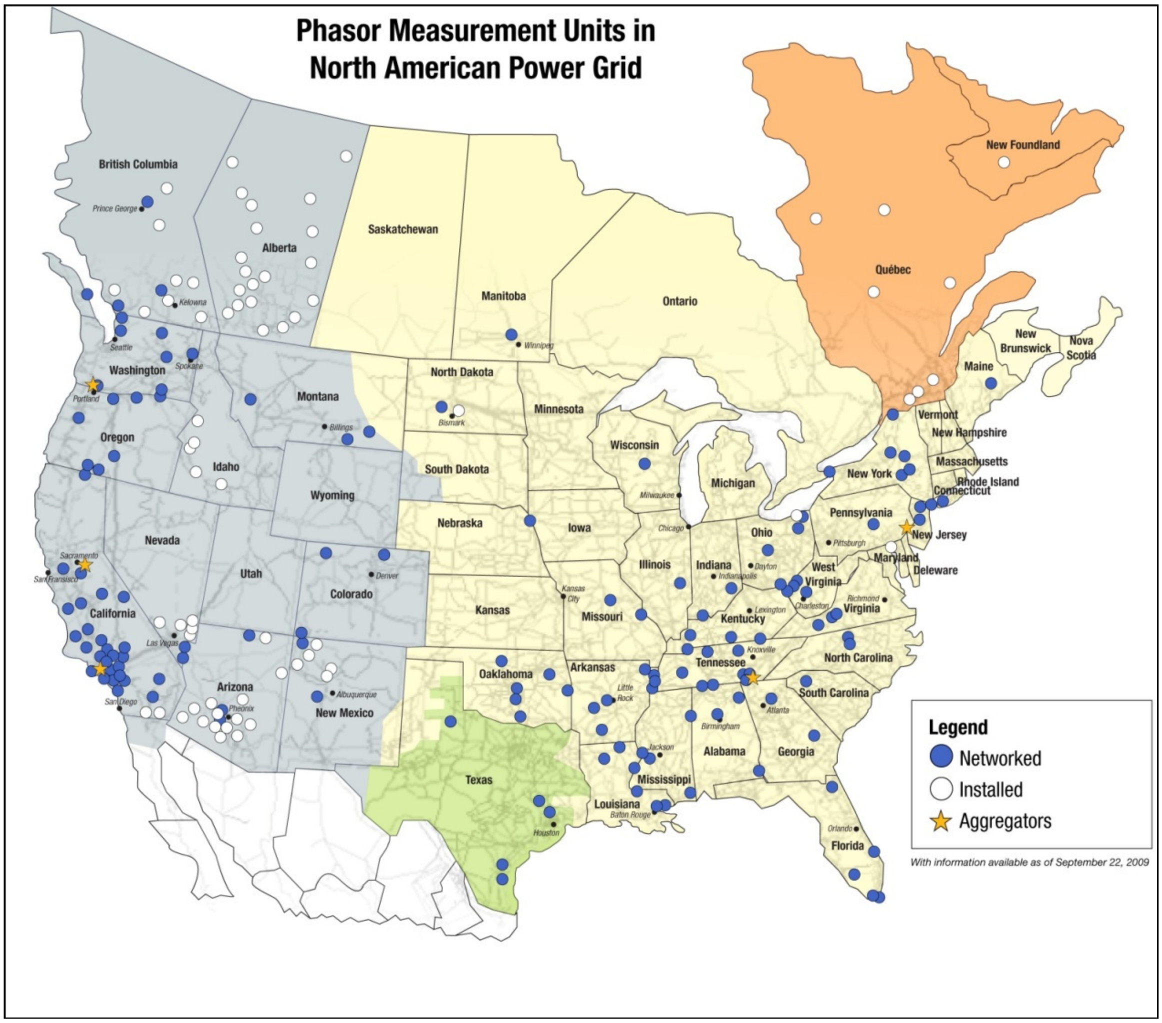


**Figure A.30**. Networked Phasor Measurement Units in the North American Power Grid[322]

### A.13.4 Challenges to Deployment

The primary challenge to deployment is making the business case that advanced measurement technologies provide benefits to justify their incremental cost. Other challenges to deployment include the need to install the measurement equipment, the networking infrastructure, and interoperability and data sharing issues. Applications such as improved visualization tools and other decision-support systems are under development and not yet routine.

[322] EIOC – Electricity Infrastructure Operations Center. *North American SynchroPhasor Initiative*. U.S. Department of Energy and Pacific Northwest National Laboratory. Accessed November 24, 2008 at http://eioc.pnl.gov/research/synchrophasor.stm/ (last updated April 2010).

Integrating and managing the large amount of information from WAMS will be a significant challenge. The Tennessee Valley Authority (TVA) is now routinely archiving PMU data from the Eastern Interconnection,[323] and BPA is doing the same in the Western Interconnection.

Data describing system state and operation are considered sensitive, and yet access to real-world phasor data is required for research. Consultants, laboratories, and academics need data to develop better hardware and software applications. To that end, NASPI is making an effort to involve more utilities in real-time data sharing and has developed a Non-Disclosure Agreement[324] requirement for continued data access to monitoring and visualization tools, to encourage that objective.

### A.13.4.1 Technical Challenges

Important technical challenges to deployment include

- The need for new measurement equipment, and new communication and networking infrastructure. This involves the coordination of several different types[325] of organizations that are required to install PMUs:
  - information technology
  - plant engineering
  - protective relaying
  - communication engineering
  - commissioning
  - transmission services.
- The development of new interoperability standards. Such standards are an active area at NIST.

[323] Zuo J, R Carroll, P Trachian, J Dong, S Affare, B Rogers, L Beard, and Y Liu. 2008. "Development of TVA SuperPDC: Phasor Applications, Tools, and Event Replay." In *Proceedings of the 2008 IEEE PES General Meeting*. July 20-24, 2008, Pittsburgh, Pennsylvania (undated webpage). Accessed October 25, 2010 at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=4596276 (undated webpage).

[324] NASPI – North American SynchroPhasor Initiative. 2008. *NASPI Phasor Data NDAs*. Accessed November 24, 2008 at http://www.naspi.org/nda/nda.stm (last updated October 2010).

[325] Weekes MA and K Walker. 2007. "PMU Challenges and Performance Issues." In *Proceedings of the 2007 IEEE Power Engineering Society General Meeting*. June 24-28, 2007, Tampa, Florida. Institute of Electrical and Electronics Engineers, Piscataway, New York. Accessed October 16, 2008 at http://ieeexplore.ieee.org/iel5/4275198/4275199/04275770.pdf?tp=&isnumber=&arnumber=4275770 (undated webpage).

- The development of improved applications such as smart grid functions, stability algorithms, and visualization tools.[326,327]
- The need to overcome reluctance to share data among utilities and others.

#### A.13.4.2 Business and Financial Challenges

While much progress has been made to integrate phasor data, software, and tools into reliability and electricity service provider settings, there remain challenges to implementation at research, planning, and operational levels:

- moving from a small-scale research environment to a full-scale commercial deployment
- operating the grid more reliably using phasor visualization tools
- broad integration of phasor data into operations, planning, and maintenance of the grid
- data storage—how much and why?
- communication issues such as speed, latency, capacity
- transfer of large volumes of synchrophasor measurements from distributed phasor data concentrators (PDC) to application server
- real-time software development
- bench marking and validation of models
- off-line analysis
- historian capabilities.

### A.13.5 Metric Recommendations

The advanced measurement systems metric presently emphasizes wide area measurements; however, future reports should consider distribution sensor systems. As the smart grid becomes a reality, it will depend increasingly on measurements made in the distribution system. That part of the system is practically unmonitored at present, yet it is the origin of the outages experienced by most people. Improved control and monitoring, aimed at such problems as self-healing and improved power quality, will depend on new low-voltage sensors, many of which are now being developed with SGIG funding. A revised metric would allow tracking of such developments.

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[326] Weekes and Walker 2007.

[327] Spiegel L, S Lee, and M Deming. 2007. *Review of Research Projects for Managing Electric Transmission Uncertainty*. Public Interest Energy Research (PIER) TRP Policy Advisory Committee Meeting and California Energy Commission Staff Workshop. August 20, 2007, Irwindale, California.

There are two potential metrics that could be helpful in describing progress for Advanced Measurement Systems in future reports:

- (Metric 13.b) The percentage of substations with equipment or feeders possessing advanced measurement technology.
- (Metric 13.c) The number of applications supported by these various measurement technologies.

These new metrics will require some development. For example, in the case of a substation with advanced measurement technology, what counts as advanced and what counts as measurement technology? Is the Advanced Metering Infrastructure that many utilities consider their entrée into the smart grid a sufficient qualification? Does a current transformer with an optical digital interface count? Are on-line (real-time) applications the only ones counted, or do applications in the "back office" that may be part of the planning process count, too? Even after these questions are answered, there remains the question of how the data would be gathered for future updates of the SGSR.

# A.14 Metric #14: Capacity Factors

## A.14.1 Introduction and Background

A capacity factor is the fraction of energy that is generated by or delivered through a piece of power system equipment during an interval, compared to the amount of energy that could have been generated or delivered had the equipment operated at its design or nameplate capacity. In principle, a capacity factor is readily understood and measured for many types of T&D equipment, including power generators, transformers, and transmission and distribution lines. Intuitively understood, a capacity factor of zero means that equipment was unused during an interval, while a capacity factor of 100 percent means that the equipment was, on average, used at its rated capacity throughout an interval. A capacity factor over 100 percent means that the equipment was overloaded, often an unsustainable or even dangerous condition. A capacity factor may, therefore, be convenient and useful as an indicator and should serve as a metric of the health and evolution of the smart grid.

Consider some of the traditional approaches to managing the capacity factor—if a transmission circuit becomes inadequate, a new circuit is built, or the circuit is reconductored to increase the corridor's design capacity. If electrical load grows, new centralized generating plants are constructed. If you install an on-demand electric water heater in your home, you and your electricity service provider must consider whether your home's distribution transformer might require replacement. Indeed, these approaches are effective at managing capacity factors and operating margins.

One objective of a smart grid is that the power system should be enabled to defer or eliminate the installation of infrastructure, thus achieving more energy production and transmission using existing equipment. Several smart grid development opportunities would directly affect, and could be monitored, at least in aggregate, by, capacity factors. Intelligent controllers might permit an electricity service provider to safely operate close to operational boundaries of installed grid infrastructure. The smart grid should recognize and mitigate stressful conditions on the grid, reacting dynamically to conditions that could overload the grid's infrastructure. Efficient loads can, of course, be supplied more easily than can inefficient ones.

The degree to which the nation has recently embraced renewable energy offers another good example with respect to this metric. Renewable generation resources such as wind are intermittent. Inclusion of an increasing number of wind generators into a capacity-factor metric will reduce the apparent aggregate capacity factor of the nation's electricity generators. Because renewable resources are often located far from population centers that would use their energy, growing renewable generation resources with varying output could create fluctuations in available transmission capacity factors as the variation in transmission flows increase either upward or downward (due to fluctuations in generation schedules). Successful implementation of DG resources, perhaps including renewable ones, near electric loads that they serve could, in principle, reduce the need to transfer much energy over distances. Distributed storage resources could achieve a similar effect. Again, one can see how this metric might be useful for surveying and discussing the effects of renewable resource penetration, even though the metric trends might be simultaneously influenced in both upward and downward directions by attributes of renewable resources.

The following two graphics (Figure A.31 and Figure A.32) from the *2009 NERC Long-Term Reliability Assessment*[328] (Generation and Transmission) show the effect of variable generation on projected transmission construction. Over the next 10 years, an additional 11,000 miles of transmission lines will need to be built for the integration of renewable resources. Similarly, 11,000 miles of transmission lines must be built to serve reliability needs.

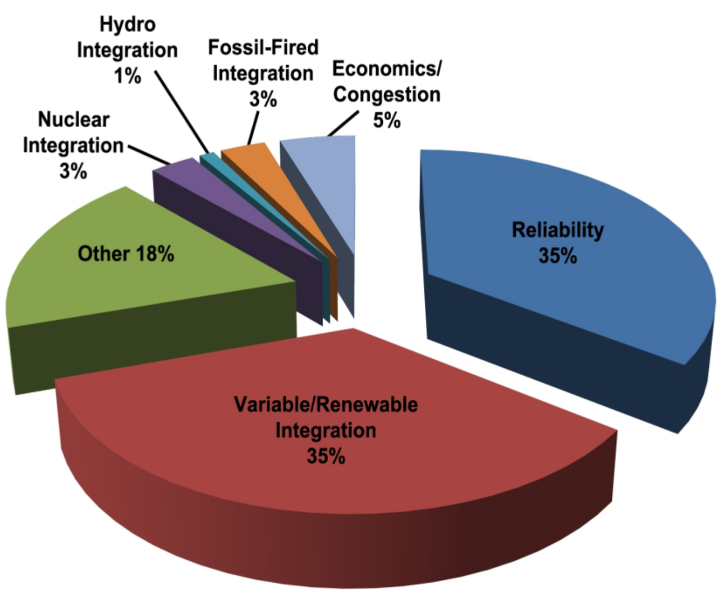



**Figure A.31**. Relative Transmission Mile Additions >200 kV by Primary Driver

[328] NERC – North American Electric Reliability Corporation. 2009a. *2009 Long-Term Reliability Assessment: 2009-2018*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed October 25, 2010 at http://www.nerc.com/files/2009_LTRA.pdf (undated webpage).

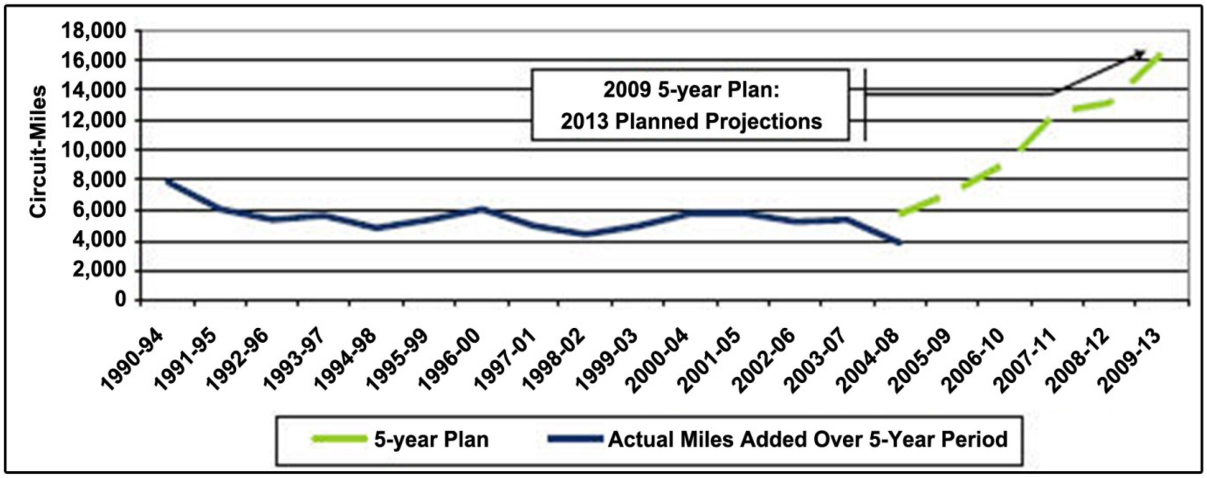
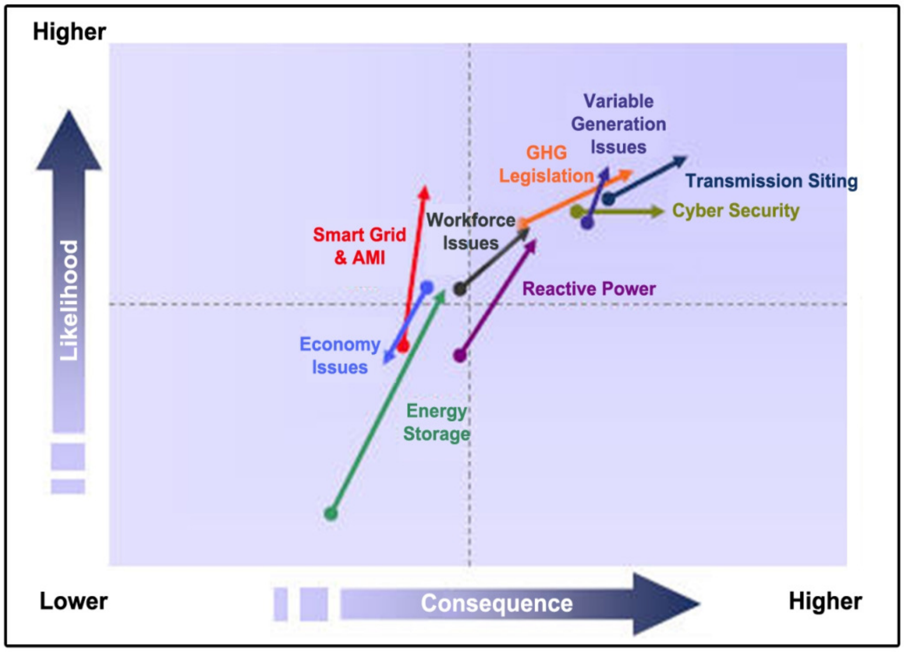



**Figure A.32**. Historical Actual Miles Added for Rolling 5-Year Periods and Projected 5-Year Plans (200 kV and Greater)

Another section of the NERC[329] report listed important emerging issues that were integral with variable generation and the need for additional transmission capacity to be built. As can be seen, these issues are a mix of policy, economic, technology, and political concerns (Figure A.33). The technology issues are intertwined with the economics of implementing new technologies within the transmission infrastructure. Policy solutions must be developed that will allow practical and cost-effective solutions to these emerging issues.

[329] NERC 2009a.




Note: The colors (of the arrows) in Figure Issues 1 were randomly chosen to differentiate overlapping arrows—colors do not represent additional data or special meaning. Arrows point from the '1-5 Years' ranking to the '6-10 Years' ranking.

**Figure A.33**. Emerging and Standing Issues 1 to 5 Years and 6 to 10 Years

Consumer trends will also affect capacity factors. Growing demand for plug-load electronics and the possibility that our consumption of fossil fuels will be displaced by EVs and PHEVs present new challenges—and perhaps opportunities—for the management of capacity factors within our distribution systems.

A smart grid could make better use of the available capacity of electricity infrastructure by flattening load profiles. Load profiles that have large diurnal and seasonal peaks stress grid infrastructure and are inefficient with respect to both cost and energy. Conduction losses increase with the square of conducted electrical current. Additionally, transmission systems are run based on an N-1 contingency, meaning one line could be lost and the system would remain stable, which increases reliability, but reduces capacity loading and increases cost. Inefficient, polluting generators are dispatched to meet only the occasional, peak demand. Therefore, not only average capacity factors, but also peak capacity factors should be measured and reported.

### A.14.2 Description of the Metric and Measurable Elements

This section defines specific measurements that will represent capacity factors across the power grid's generation, transmission, and distribution systems, as well as across major types of power-grid equipment, including generators, conductors, and transformers.
Three measurements that pair generation with generators, transmission with conductors, and

the distribution system with transformers are proposed. Each pairing invites and defines both average and peak capacity-factor measurements.

*(Metric 14.a) Yearly average and peak generation capacity factor (%)*—the yearly average capacity factor of the nation's entire generator population should be estimated (see Equation 14.a).

This metric requires that the total national electricity generation and the total electricity generation nameplate or design capability of the nation's generators be accurately estimated each time this metric is to be updated. With minor modification of this calculation, one can estimate the yearly or average daily peak generation capacity factor answering, "How close did the nation come last year to exceeding its generation capacity?"

$$CF_{\text{Generation}}(\%) = \frac{\sum\limits_{\textit{All Generators}} \sum\limits_{\text{Year}} \text{Generated Energy (MWh)}}{8760\,\text{(hours)} * \sum\limits_{\textit{All Generators}} \textit{Generator Power Rating}\,(MW)} * 100\,(\%) \tag{14.a}$$

*(Metric 14.b) Yearly average and average peak capacity factors for a typical mile of transmission line (%-mile per mile)*: capacity factor of the nation's transmission lines should be estimated, the result being weighted to account for transmission line distances (see Equations 14.b1 [per line] and 14.b2 [distance weighted]).

A minor modification of this measurement can be performed to also provide the yearly or daily average *peak* transmission capacity factor on a mile of our nation's transmission lines during the year.

$$CF_{\text{Trans. Line}}(\%) = \frac{\sum\limits_{\text{Year}} \text{Transmitted Energy (MWh)}}{8760\,\text{(hours)} * \sum \text{Line Power Rating (MW)}} * 100\,(\%) \tag{14.b1}$$

$$CF_{\text{Per Mile Trans. Line}}(\%) = \frac{\sum\limits_{\text{All Lines}} \text{Line Distance (miles)} * CF_{\text{Trans. Line}}(\%)}{\sum\limits_{\text{All Lines}} \text{Line Distance (miles)}} \tag{14.b2}$$

*(Metric 14.c) Yearly average and average peak distribution-transformer capacity factor (%)*: estimate of the average capacity factor of the nation's distribution transformers over the year (see Equation 14.c).

This calculation may be modified to further define the yearly or average daily *peak* distribution-transformer capacity factor across all distribution transformers.

$$CF_{\text{Dist. Xfmr}}(\%) = \frac{\sum_{\text{All Xfmrs.}} \sum_{\text{Year}} \text{Xfmr.Energy}(\text{MWh})}{8760\,(\text{hours}) * \sum_{\text{All Xfmrs.}} \text{Xfmr.Ratings}(\text{MW})} * 100(\%)$$

**(14.c)**

### A.14.3 Deployment Trends and Projections

Data useful for metric measurement 14.a were found concerning our nation's generation adequacy. Measurement of this metric relied on data collected and forecast by NERC.[330] NERC data measure peak summer demand and summer generation capacity, peak winter demand and winter generation capacity, and yearly energy demand for each major NERC region. Published data included measurements from 1989 through 2006 and projected estimates through 2016. Table A.18 summarizes the resulting Metric 14.a capacity factor measurements for two years—2006 and 2008, the most recent year for which measured data were available. On average, a little less than half of the nation's generation capacity is now used, but less than 25 percent of the nation's total generation capacity remains unused during summer peaks. Smart grid techniques may lead to increased asset utilization over time, thus increasing overall capacity factors.

**Table A.18**. Measured and Projected Peak Demands and Generation Capacities for Recent Years in the U.S.[331] and Calculated Capacity Factors

| | 2006 Measured | 2008 Measured |
|---|---|---|
| Summer Peak Demand (MW) | 789,475 | 755,614 |
| Summer Generation Capacity (MW) | 954,697 | 977,991 |
| Capacity Factor 14.a, Peak Summer (%) | 82.69 | 75.71 |
| Winter Peak Demand (MW) | 640,981 | 644,869 |
| Winter Generation Capacity (MW) | 983,371 | 976,258 |
| Capacity Factor 14.a Peak Winter (%) | 65.18 | 66.05 |
| Yearly Energy Consumed by Load (GWh) | 3,911,914 | 3,989,058 |
| Capacity Factor 14.a, Average (%) [(a)] | 46.08 | 46.13 |
| (a) The average of the NERC (2006 & 2008) summer and winter capacities for each year was used for this calculation | | |

Some trends can be observed in data presented in Figure A.34, which presents actual capacity factor data back to 1989 and forecast data out to 2014. According to NERC data, the U.S. crept closer to its generation limits for at least the ten years preceding 1998 to 2000, but it

[330] NERC – North American Electric Reliability Corporation. 2009b. *2009 Reports (with 2008 Actuals)*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed September 25, 2010 at http://www.nerc.com/page.php?cid=4|38|41 (last updated December 22, 2009).

[331] NERC 2009b.

reversed that trend during the next five years and returned to more conservative generation capacity factors. Relatively constant generation capacity factors are predicted for the next eight years.

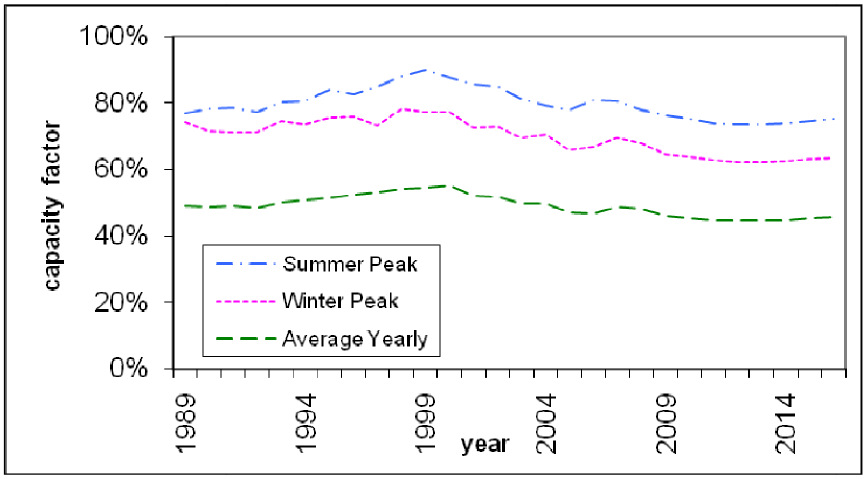



**Figure A.34**. Measured and Predicted Peak Summer, Peak Winter, and Yearly Average Generation Capacity Factors in the U.S.[332]

Capacity factors have declined from the previous SGSR primarily due to the recent economic downturn. Load dropped as business activity declined (Figure A.35), leaving a similar amount of generation to serve less load, thus reducing the capacity factor. Data of this quality were not found for the other two recommended measurements, 14.b and 14.c, concerning capacity factors that would indicate the status of the nation's transmission and distribution systems.

[332] NERC 2009b.

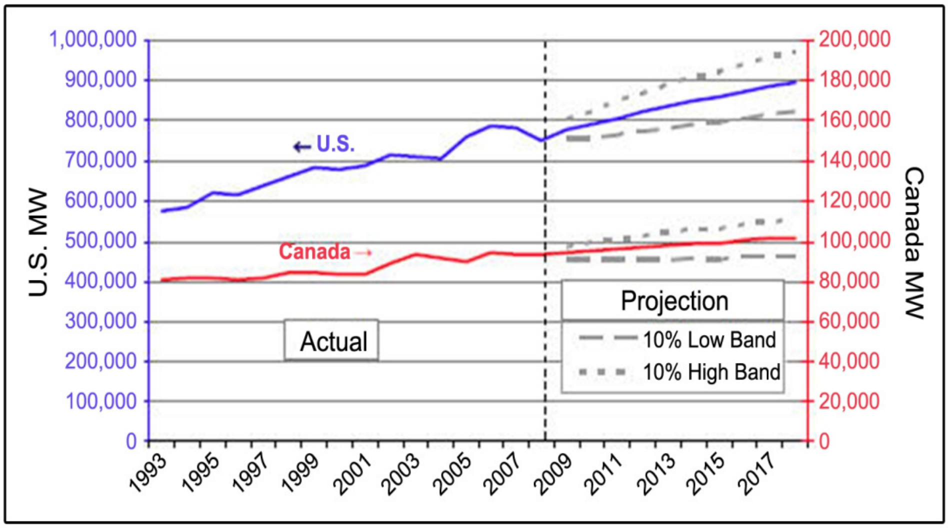



**Figure A.35**. 2009 to 2018 Peak Demand Projection[333]

Policymakers and regulators at the federal and state levels have identified demand-side management as a tool to reduce the need for new peak energy sources. Consequently, energy efficiency and demand response are projected to reduce peak-demand growth, as well as defer the need for additional generating capacity. Much of the peak-demand reduction will be contributed by just a few subregions where programs and policies are in place to drive demand response. The New England ISO has a particularly progressive program that includes active auditing and monitoring of energy efficiency resources being installed, with their consequent embedding in load forecasts as demand reductions.

Planning-reserve margin is the measure of generation capacity available to meet expected demand in a planning horizon time frame. This technique has been in use by planners for decades as a relative indication of adequacy. Adequate capacity is needed to maintain reliable operation during extreme weather conditions and during unexpected outages. The declining reserve margins present in the U.S. grid imply the capacity factor for generation in the summer is declining and could indicate reduced reliability. Figure A.36 illustrates the forecast aggregate U.S. reserve margin between 2009 and 2018.

[333] NERC 2009a.

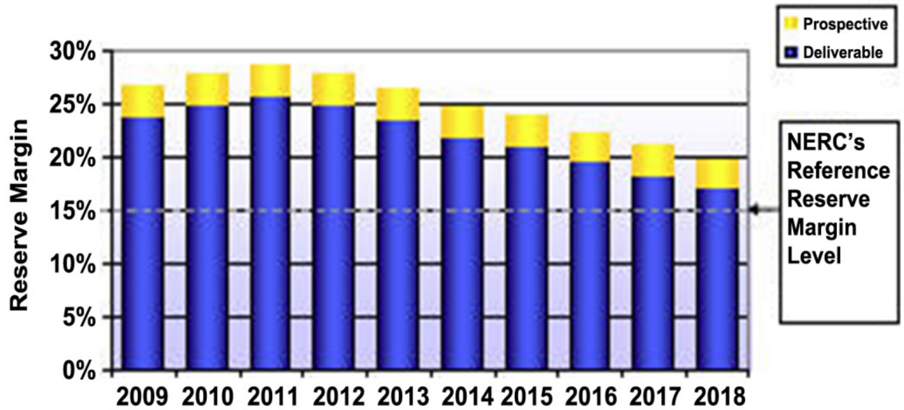



**Figure A.36**. NERC U.S. Summer Peak—Planning Reserve Margin[334]

#### A.14.3.1 Stakeholder Influences

Our nation's electrical grid is regulated mostly on a federal and state-by-state basis, and involves the participation of a very large number of stakeholders. More specifically

- policy advocates – Metric 14 should provide evidence of clear trends for policy advocates. The metric should especially help advocates verify claims that the power grid is adequate or inadequate for the anticipated growth of electricity usage. These trends could also help support smart grid policies that would flatten load profiles or would allow operation with smaller operational margins.
- reliability coordinators including NERC – The three measurements of this metric measure generation, transmission, and distribution-transformer margins. Capacity margin information is important for reliability coordinators and system planners to monitor.
- generation and demand wholesale-electricity traders/brokers – Understanding the capacity factor within a marketplace is important for rational participation by market players. Since enhanced information can provide a competitive edge, detailed data are often protected.
- balancing authorities – The ability to balance load and generation is affected by the availability of generation resources and may be limited by transmission constraints that have some reflection in the capacity metric.
- transmission providers – Through Equation 14.b, this metric provides a benchmark for transmission providers concerning their relative practices for loading transmission lines.
- distribution-service providers – Through Equation 14.c, this metric provides distribution-service providers a benchmark concerning their practices of loading provided distribution equipment—transformers, in this case.

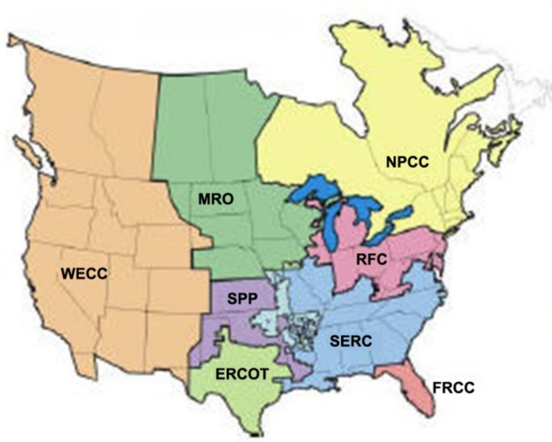
[334] NERC 2009a.

- electric-service retailers – This metric provides general information over time about the effects of changes in customer energy usage. PHEVs, for example, are a technology that have the potential to drastically change the way we use our existing electric distribution system and may have ramifications on the way retailers can supply such electrical load.
- end users – End users should benefit indirectly from the improved reliability that could result from our improved understanding of the adequacy and operational margins built into our grid infrastructure.

### A.14.3.2 Regional Influences

NERC[335] data for regions within the U.S. show some interesting trends. Figures A.37 through A.45, all derived from the *2009 NERC Long-Term Reliability Assessment* report, demonstrate that projected performance varies much more between regions than past performance. However, as would be expected, regions appear to alter their strategies and investments to meet their own challenges and bring their performance more in line with that of neighboring regions over time.

Updates to NERC reporting of summer capacity versus demand have become more granular than in the past when a composite table for all regions was used. Beginning with the *2009 NERC Long Term Reliability Assessment* report, regional graphs were produced rather than composite information.




***Note**: The highlighted area between SPP and SERC denotes overlapping Regional area boundaries: For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

| NERC Regional Entitites | |
|---|---|
| **ERCOT** Electric Reliability Council of Texas | **RFC** Reliability *First* Corporation |
| **FRCC** Florida Reliability Coordinating Council | **SERC** SERC Reliability Corporation |
| **MRO** Midwest Reliability Organization | **SPP** Southwest Power Pool, Incorporated |
| **NPCC** Northeast Power Coordinating Council, Inc. | **WECC** Western Electricity Coordinating Council |

**Figure A.37**. NERC Regions[336]

[335] NERC 2009a.
[336] NERC 2009a.

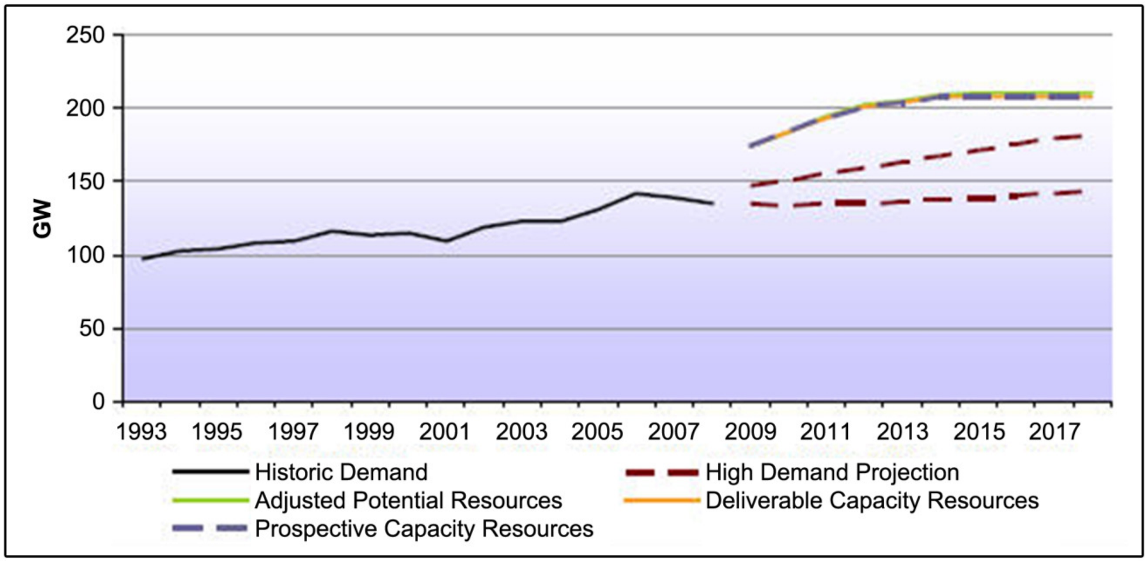



**Figure A.38**. WECC U.S. Measured and Projected Capacity vs. Demand—Summer

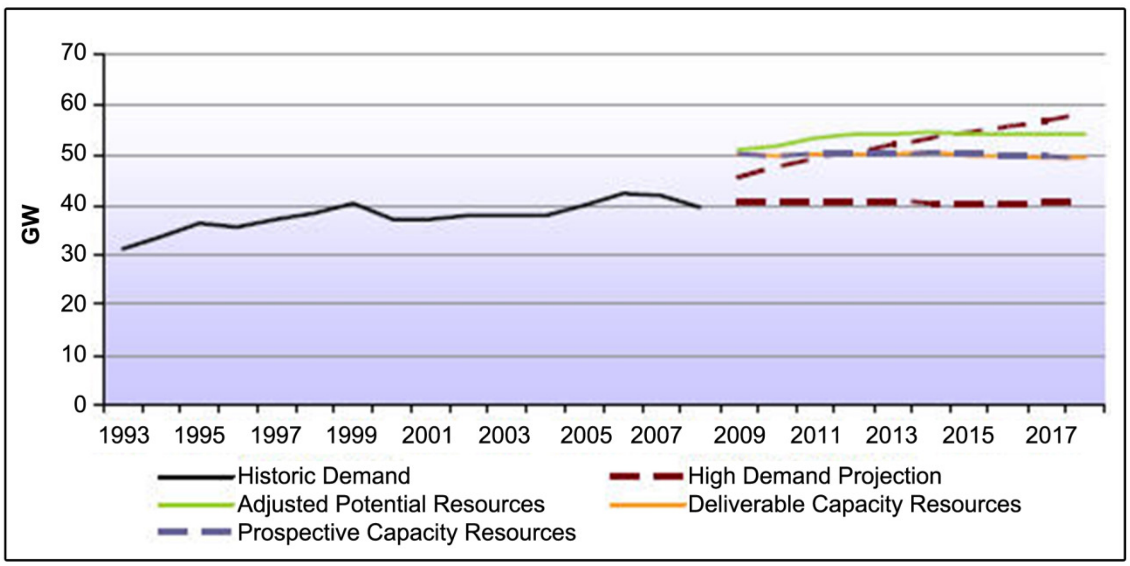



**Figure A.39**. MRO U.S. Measured and Projected Capacity vs. Demand—Summer

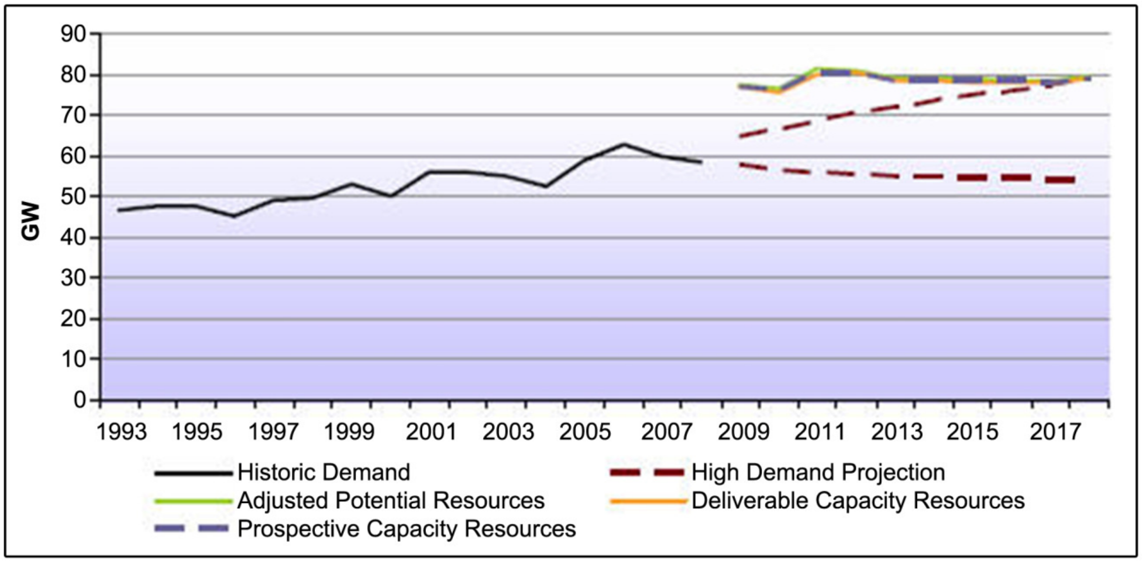



**Figure A.40**. NPCC U.S. Measured and Projected Capacity vs. Demand—Summer

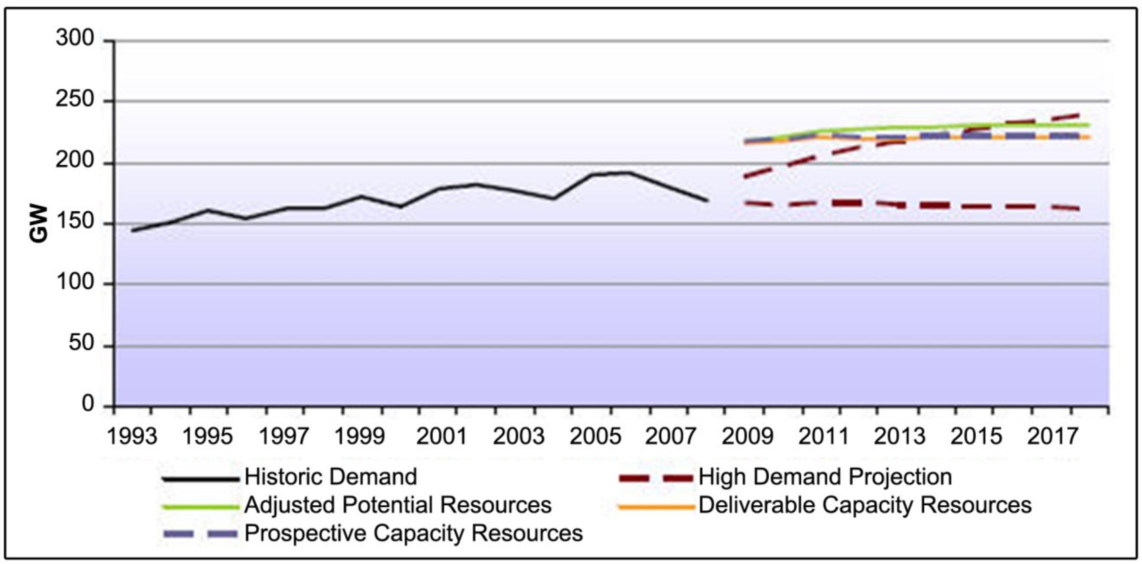



**Figure A.41**. RFC Measured and Projected Capacity vs. Demand—Summer

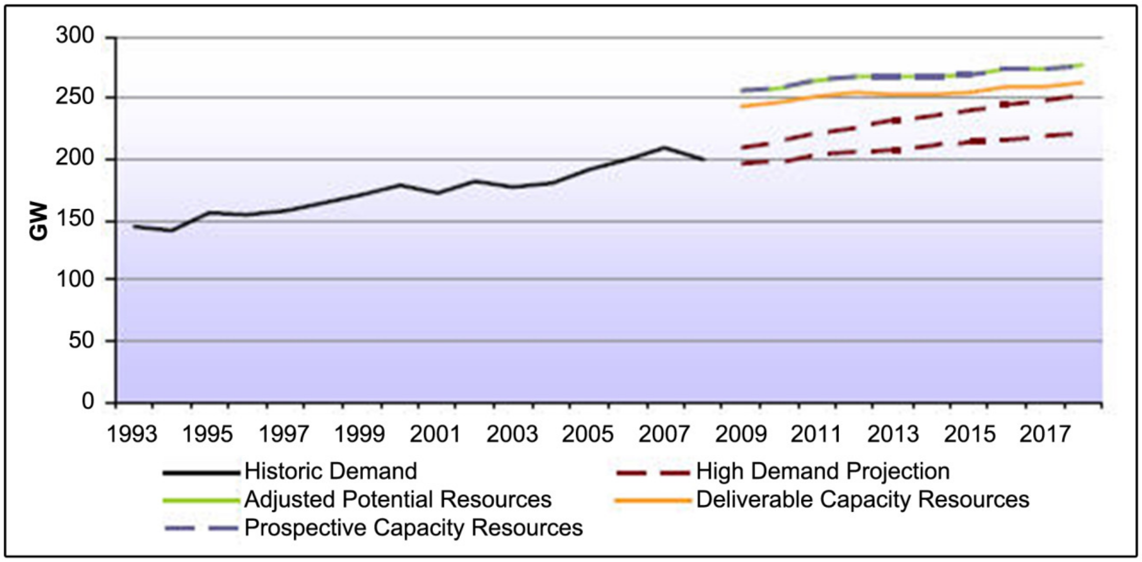



**Figure A.42**. SERC Measured and Projected Capacity vs. Demand—Summer

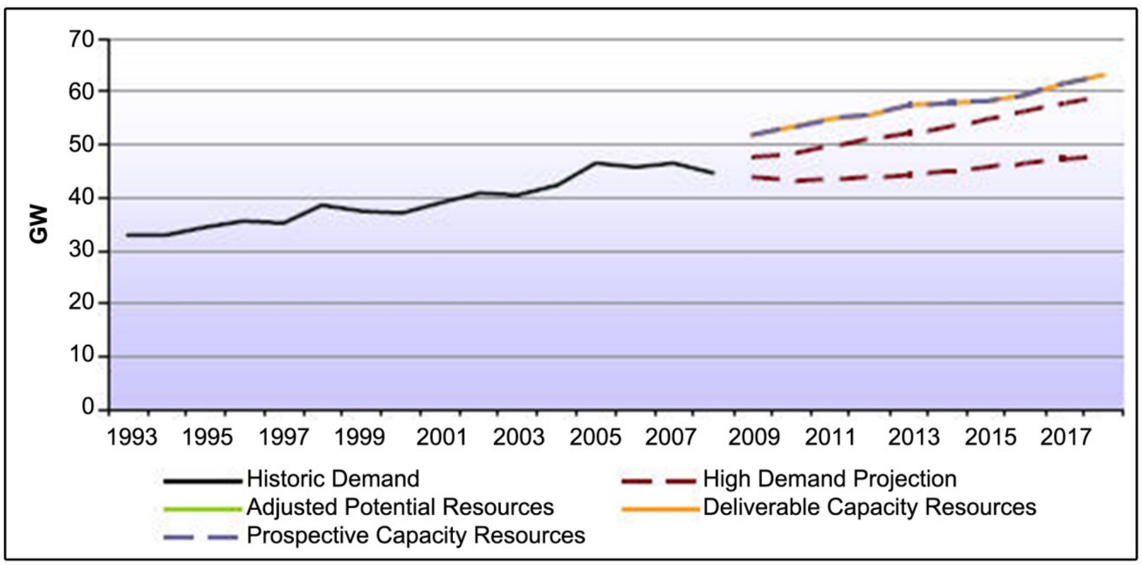



**Figure A.43**. FRCC Measured and Projected Capacity vs. Demand—Summer

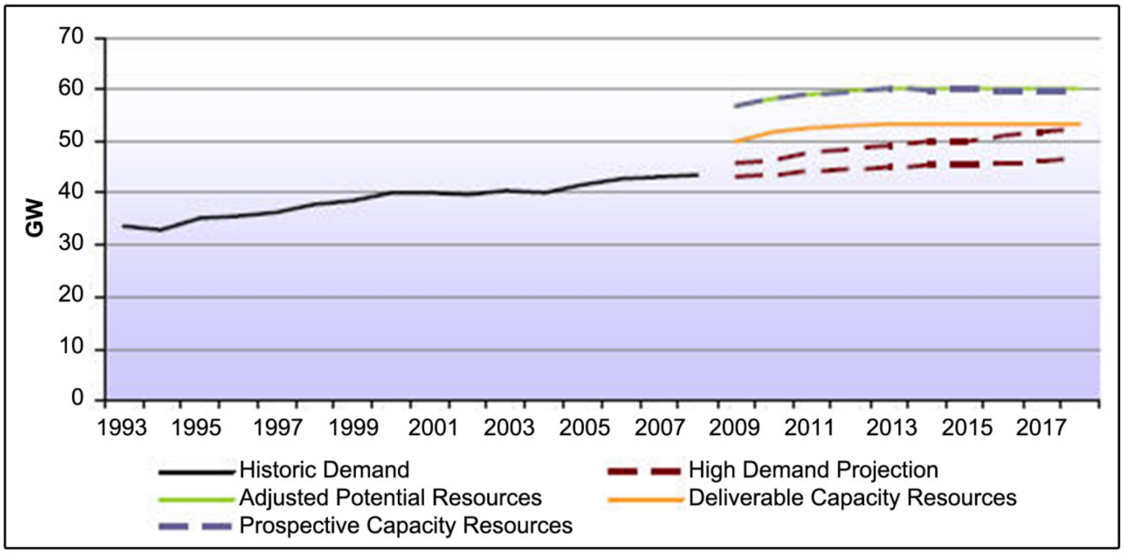



**Figure A.44**. SPP Measured and Projected Capacity vs. Demand—Summer

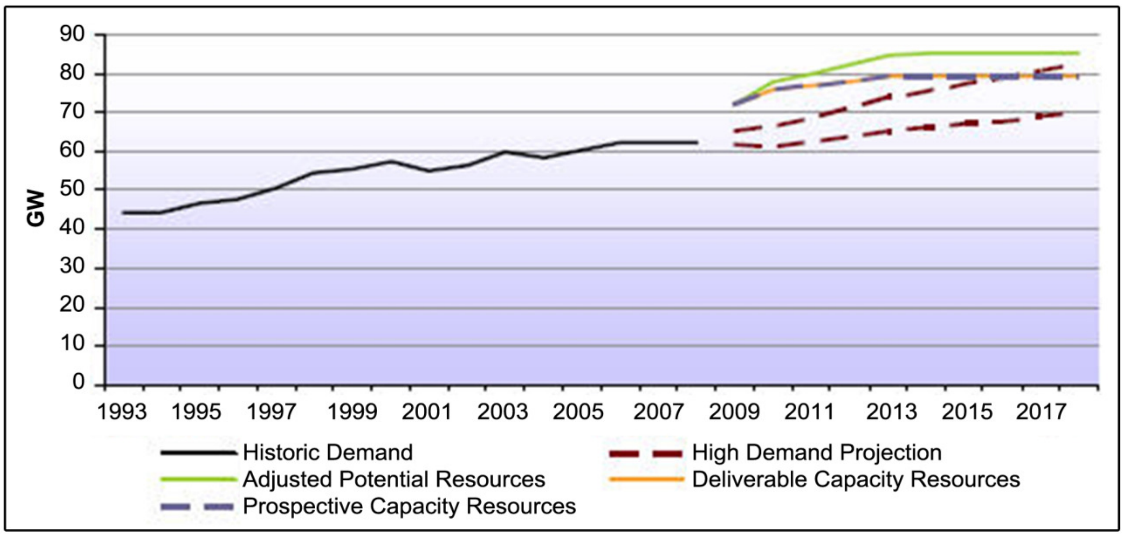



**Figure A.45**. ERCOT Measured and Projected Capacity vs. Demand—Summer

### A.14.4 Challenges

Many technical, business, and policy challenges potentially hinder the use of the capacity factor as a metric of smart grid evolution.

#### A.14.4.1 Technical Challenges

Capacity factors are not typically shared among utilities and regions. The large quantities of equipment at the generation, transmission, and distribution levels will make this metric difficult to track without accepting a statistical-sampling approach for the recommended measurements. Because changes in power-grid infrastructure occur relatively slowly, it will be challenging to obtain useful measurements with an accuracy that supports a meaningful monitoring of system trends over time using capacity factor measurements.

The continued increase in installed variable generation, predominately wind, can increase operational challenges. A rapid increase or decrease of wind generation, often referred to as "ramping," can have a significant impact on the power flowing through the bulk power system. Operational impacts of wind generation on regulation and control performance of the bulk power system are still not fully understood. Many wind integration studies in the U.S. have provided information about the effects of wind on the bulk power system. Further study and industry experience will be required to mitigate operational concerns and support large-scale integration of variable generation.

To address operational issues, NERC and the NERC Regions have begun several initiatives to facilitate the reliable integration of variable generation. These coordinated initiatives include focused work groups, integration studies, equipment and system modifications, and increased forecasting efforts.

#### A.14.4.2 Business and Financial Challenges

Because the grid spans multiple regions, industries, and functions, it is challenging to obtain the necessary information on the state of the grid. In addition, it can be difficult to identify those responsible for coordinating and sharing responsibility for making capacity enhancements. This leads to challenges in creating incentives to invest in smart grid technology that can better manage capacity factors.

### A.14.5 Metric Recommendations

Data were not readily found for measurements using Equations 14.b and 14.c concerning our nation's transmission and distribution transformer infrastructure. It is recommended that samplings be performed to estimate these metric measurements. The inability to use Equations 14.b and 14.c is driven by the fact that there is no information regarding individual transmission-line capacity in a compiled form. No electricity service provider provides data as to the size and loading of distribution transformers. Without these two pieces of data, these metrics aren't calculable and, therefore, are not usable. Further, if future interviews of electricity service providers are conducted, they should include questions that more precisely address these metric measures.

# A.15 Metric #15: Generation, Transmission, and Distribution Efficiency

## A.15.1 Introduction and Background

The generation of electricity from thermal sources is unavoidably inefficient. The efficiency depends on the values of the highest and lowest temperatures in the system. Expressed in degrees above absolute zero, these values are often close to one another. The best efficiency that can be obtained by a perfect machine is given by the difference in temperature divided by the higher temperature:

$$\text{Efficiency} = T_{diff}/T_{high} = 1 - T_{low}/T_{high}$$

If the low and high temperatures are the same, the efficiency is zero. The fraction of total energy that can be extracted from a thermal process was studied by Carnot as long ago as 1824, and the cycle used in an internal combustion engine is named after him.

Once electricity has been generated, the delivery process is much more efficient, though the large quantity distributed means that even a small loss represents a significant dollar amount. Generation, transmission, and distribution efficiencies are measured by the EIA, and are represented in Figure A.46.[337] Generation efficiency is measured in terms of heat rate, or the ratio of delivered electric energy to the chemical energy in the fuel input. Transmission and distribution efficiency are measured by the line losses incurred in transporting the energy. The relative importance of these two factors can be judged from Figure A.46. Note that although the energy lost to transmission and distribution is small compared to the Carnot-cycle losses, they are significant, and are worth addressing.

[337] EIA – Energy Information Administration. 2009. *Annual Energy Review 2009*. DOE/EIA-0384(2009), Energy Information Administration, Washington, D.C. Accessed August 30, 2010 at http://www.eia.doe.gov/aer/elect.html (undated webpage).

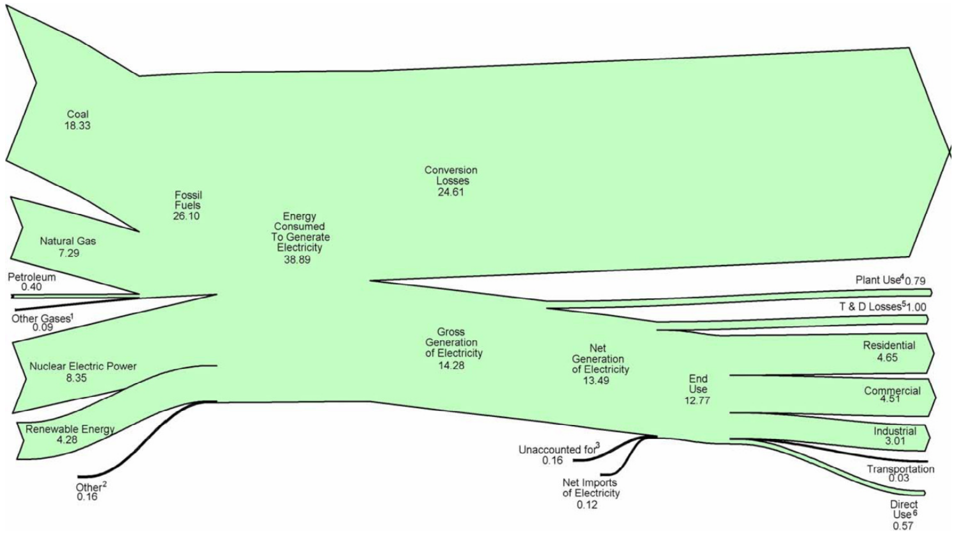



**Figure A.46**. Electricity Flow Diagram 2009 (Quadrillion Btu)[338]

## A.15.2 Description of Metric and Measurable Elements

(Metric 15) The energy efficiency of electric power generation and delivery (T&D).

For generation, energy efficiency is subdivided into coal, petroleum, and natural gas; non-fossil sources are not considered in this metric. The combination of coal, petroleum, and natural gas makes up about 80 percent of the nation's electric power generation base. Because losses for T&D are so low in comparison and associated data lack granularity, they are grouped together.

## A.15.3 Deployment Trends and Projections

It is clear from Figure A.47 that the total amount of electricity consumed has significantly increased during the past few decades, and the majority of the energy comes from fossil fuels. From this we may conclude that improving efficiency will be of continuing importance.

[338] EIA 2009.

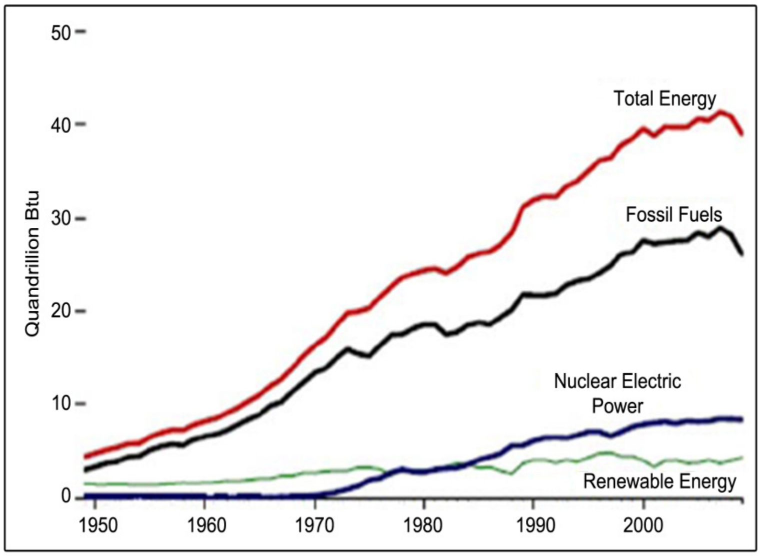



**Figure A.47**. Energy Consumption for Electricity Generation by Source

Demand-side management programs and state-level electricity restructuring have increased competition among service providers, thus promoting greater generation efficiency. Increased numbers of privately owned generation units and competitive wholesale electricity markets have prompted electricity providers to take steps to reduce operating costs and improve their operating performance.[339] In general, providers with lower generation costs are better able to maintain their market shares and maximize profits in wholesale electricity markets.

Generation efficiency varies greatly depending on the electricity type, method of generation, and technology (including age) used for generation. According to the EIA, electricity produced from coal currently represents approximately 45 percent of all generation in the U.S., with efficiency levels of approximately 30 to 35 percent (see Figure A.48). New "clean coal" technologies such as carbon capture and storage (CCS) promise to enhance efficiency levels and are actively promoted by the DOE through Clean Coal Technology & Clean Coal Power Initiatives.[340] Work is also being done to construct the "zero emission" coal plant of the future, a technology being developed to include CCS, and is expected to come to fruition in the mid 2020s.[341]

[339] Wolfram C. 2003. *The Efficiency of Electricity Generation in the U.S. After Restructuring*. CSEM WP 111R, Center for the Study of Energy Markets, University of California Energy Institute, Berkeley, California. Accessed October 25, 2010 at http://escholarship.org/uc/item/94j492v4#page-1 (undated webpage).

[340] DOE – U.S. Department of Energy. 2010. *Clean Coal Technology & The Clean Coal Power Initiative*. U.S. Department of Energy, Washington, D.C. Accessed January 17, 2011 at http://www.fossil.energy.gov/programs/powersystems/cleancoal/ (last updated June 7, 2010).

[341] Beér J. 2007. "High Efficiency Electric Power Generation; The Environmental Role." *Progress in Energy and Combustion Science* 33(2):107-134, DOI: 10.1016/j.pecs.2006.08.002.

Generation in the United States has seen relatively steady efficiency rates in the last 50 years, following rapid growth in the efficiency of coal power in the 1950s. Single cycle steam Rankine plants (coal and nuclear) produce the vast majority of electricity in the U.S. These plants, though not as efficient as some others, use relatively inexpensive fuels, are less capital intensive than most renewable resources, and operate at much higher annual capacity factors than renewables. The leveling off of coal, and decrease since the 1950's in the use of petroleum, now at a very small percentage of annual energy production, suggests the limitation of the Carnot efficiency for large plants, while the increase in gas efficiency shows the improvement from gas turbines, mostly due to greater use of combined cycle power plants. Figure A.48 illustrates the improved efficiency of generators in the United States over time.

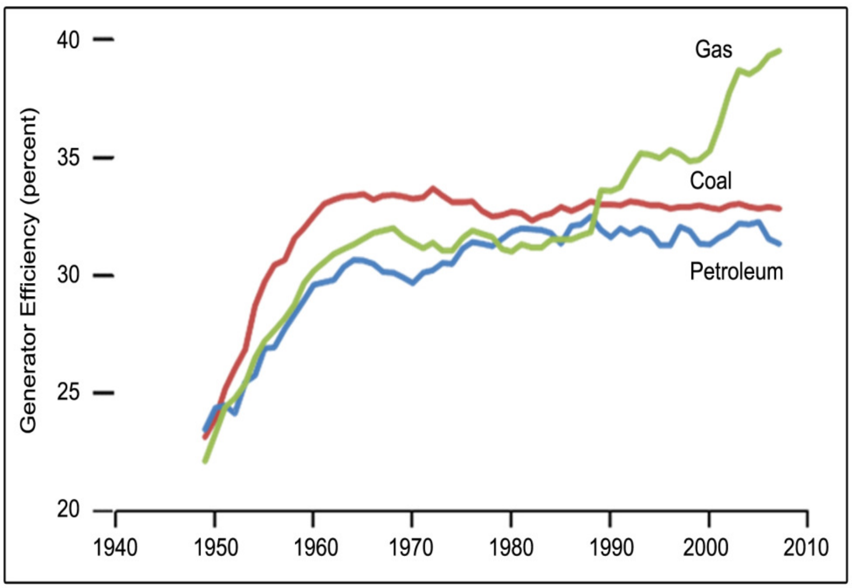



**Figure A.48**. Generation Efficiency for Various Fossil Fuel Sources over Time[342]

Figure A.49 shows the relatively high efficiency of transmission and distribution assets, with an almost steady level of efficiency over the past two decades. That is, T&D efficiency (ignoring direct-use values) grew to 94.1 percent in 2008 from 92.3 percent in 1995. These numbers represent significant gains in T&D efficiency since data were first collected.

In 2008, total T&D losses were 245.9 billion kWh. EIA data show a total of about 4,000 billion kWh net generation and imports less for the year, so that the losses are about 6.1 percent. While the efficiency number seems positive, the energy loss is equivalent to continuous generation of 28 GW, approximately the level produced by 29 large power stations. Work on improving the situation is clearly still justified.

[342] EIA – Energy Information Administration. 2007b. *Annual Energy Review 2007*. DOE/EIA-0384(2007), Energy Information Administration, Washington, D.C. Accessed October 11, 2010 at http://www.eia.gov/FTPROOT/multifuel/038407.pdf (undated webpage).

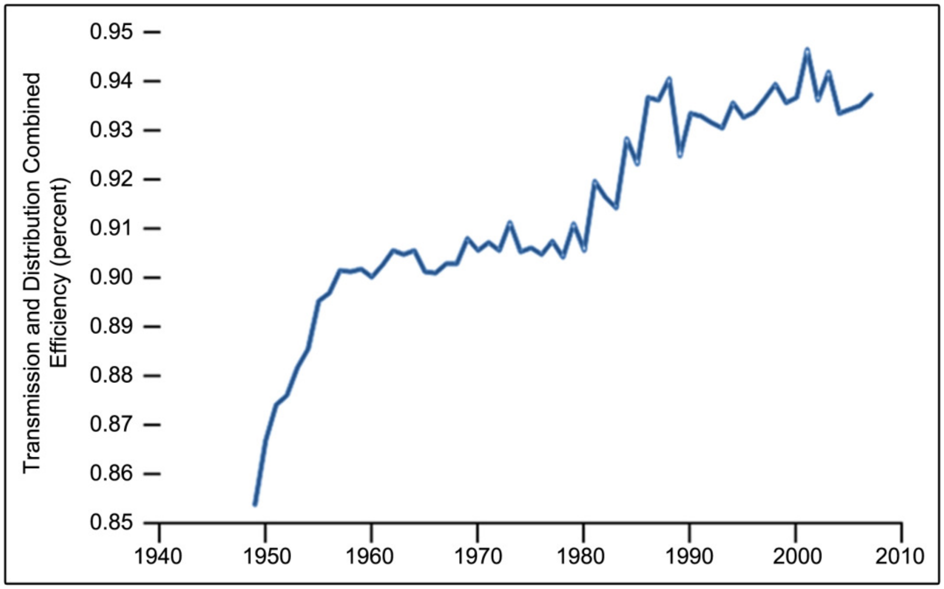



**Figure A.49**. Combined Transmission and Distribution Efficiency over Time[343]

EPRI has launched two new initiatives: one for improving the efficiency of the transmission grid and the other for improving the efficiency of the distribution grid.[344] DOE is also working on related technology. A $3.7 million grant was recently awarded by DOE to the Durham, North Carolina-based company, Cree, which is developing high-voltage silicon carbide transistors for power management in electrical substations.[345]

### A.15.3.1 Associated Stakeholders

Associated stakeholders include:

- generation operators – Higher generation efficiency and reduced losses should mean greater profits for service providers. Generation operators may also be constrained by emissions requirements. Hence, using more efficient generators that discharge fewer emissions will be of interest.

[343] EIA 2009.

[344] EPRI – Electric Power Research Institute. 2009. *Transmission Efficiency Initiative: Key Findings, Plan for Demonstration Projects, and Next Steps to Increase Transmission Efficiency*. Document Number 1017894, Final Technical Update October 2009. Electric Power Research Institute, Palo Alto, California. Accessed September 2010 at http://mydocs.epri.com/docs/CorporateDocuments/SectorPages/PDU/1017894TransmissionEfficiencyWorkshop11-09.pdf (undated webpage).

[345] *Datacenter Dynamics*. July 13, 2010. "US DOE Invests $92m in Energy Storage, Transmission and Cooling-Efficiency Research." Accessed September 1, 2010 at http://www.datacenterdynamics.com/ME2/dirmod.asp?sid=&nm=&type=news&mod=News&mid=9A02E3B96F2A415ABC72CB5F516B4C10&tier=3&nid=7108F320991B40D78AD32A412FDC60D0 (last updated July 13, 2010).

- regional transmission operators – Power-line losses can lead to congestion on a transmission path. Sometimes the situation requires grid operators to change generation schedules in some areas to protect the integrity of the grid as a whole. These "transmission loading relief" actions (TLRs) tend to peak in the summer months, and are logged by NERC at a rate of a few hundred per month (300/month in July 2010).[346] Hence, RTOs would benefit from higher transmission efficiency.
- local, state, and federal energy policymakers (regulators) – Greater efficiency would mean reduced dependence on foreign fuel supplies, be they oil or natural gas or even coal, which pays obvious dividends from a security standpoint.
- end users (consumers) – Transmission constraints cost consumers billions of dollars in congestion charges passed down from the utilities.
- policy advocates (environmental groups) – From an environmental perspective, greater generation efficiency leads to lower fuel usage and fewer emissions.

#### A.15.3.2 Regional Influences

Regional influences emerge due to the large differences in energy resources in various parts of the country. While fossil-fuel power plants are the largest producers of electricity in the U.S., in some parts of the nation, nuclear or hydroelectric power play important roles.

The average generation efficiency is different among the states. This difference is attributed to the average heat value of the coal, petroleum, and natural gas used in the states. For example, in 2008, the average heat value of coal used in Texas was 7,759 Btu per pound, while in California it was 11,667 Btu per pound.

### A.15.4 Challenges to Deployment

#### A.15.4.1 Technical Challenges

Perhaps it is fair to say that the "easy" improvements to efficiency have already been made. New initiatives in generation efficiency include improving the heat rate/emission rate/efficiency using carbon capture and sequestration.[347] The work is proving costly and challenging.

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[346] NERC – North American Electric Reliability Corporation. 2010. "Trend Charts." *Transmission Loading Relief (TLR) Procedure*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed September 1, 2010 at http://www.nerc.com/docs/oc/scs/logs/trends.xls (undated webpage).

[347] Nawaz M and J Ruby. 2001. "Zero Emission Coal Alliance Project Conceptual Design and Economics." In *Proceedings of the 26th International Technical Conference on Coal Utilization and Fuel Systems*. March 5-8, 2001, Clearwater, Florida. Accessed October 25, 2010 at http://manhaz.cyf.gov.pl/manhaz/links/COAL_BASED_NEW_TECHNOLOGIES/conceptual_design_and_econ.pdf (undated webpage).

Reducing T&D losses would require adding high-voltage power lines (which is a strategy that usually runs into public opposition), finding better low-loss conductors and finding smarter, more efficient ways of moving power from congested, high-loss transmission corridors. Smart grid initiatives that install synchrophasors would benefit service providers by giving them real-time information on the status of their transmission systems.

Improving transmission efficiency for large transfers of bulk power will be driven in part by new High Voltage Direct Current (HVDC) lines. HVDC lines are used to transfer large amounts of power, with low energy losses, over distances longer than 400 miles on land or via underwater cables longer than 30 miles. Currently, the major U.S. HVDC lines are located in the WECC and run into Los Angeles from the Pacific Northwest and Colorado. There are several new HVDC lines proposed for construction in the WECC area, including the Northern Lights Celilo and Northern Lights Zephyr projects.

AC at high voltages (115kv to 765kv) currently dominates U.S. transmission infrastructure due to the ease with which it is routed or tapped via switches (circuit breakers). HVDC lines are currently very expensive to switch; consequently if an HVDC circuit breaker could be developed, it could significantly improve transmission efficiency.

#### A.15.4.2 Business and Financial Challenges

Electricity service provider cultures with traditionally low risk tolerance may not be well equipped to deal with the needs of an evolving marketplace. There are challenges in several areas:

- While there are plenty of infrastructure improvements envisioned, such as superconducting cables, and energy-storage options, these options are high cost, and work primarily for niche problems.
- Significant improvements in energy efficiency will require active involvement by the electricity service provider.
- Utilities or aggregators may be involved in demand response as a way to reduce peak loads. Improving price transparency and customer participation will be vital in managing the electric power system efficiently in the future.

Energy efficiency can be thought of as a good source of energy. While many of the largest assets have been operating without significant improvement for decades, investments in new technologies can provide new opportunities for electricity providers to make efficiency gains.

### A.15.5 Metric Recommendations

The electricity flow diagram data collected and reported by the EIA is crucial for this metric and needs to be updated regularly. It should also include emerging technologies in the various generation and storage areas. Finally, it should include reasons for efficiency improvements and losses, if any.

# A.16 Metric #16: Dynamic Line Ratings

## A.16.1 Introduction and Background

Dynamic line ratings (DLR), also referred to as real-time transmission line ratings, are a well-proven tool for enhancing the capability and reliability of our electrical transmission system. Modern DLR systems can be installed at a fraction of the cost of other traditional transmission line enhancement approaches.

The Edison Electric Institute reports that $56 billion will be spent between 2009 and 2020 on transmission upgrades. Of this amount, only $436 million will be invested in smart grid applications, and most of that will be spent on synchrophasor measurement units.[348] This compares with approximately $298 billion that the Brattle Group has estimated is required to upgrade transmission capability to meet future demand.[349]

One of the primary limiting factors for transmission lines is temperature. When a transmission line current increases, the conductor heats, begins to stretch, and causes the power line to sag. Allowable distances between power lines and other obstacles are specified by the National Electric Safety Code (NESC).

The amount of sag in a span of transmission line depends primarily on the conductor's material characteristics and construction. While line sag can be calculated with reasonable engineering accuracy for newer lines, the amount of sag an older line will exhibit is less predictable. Transmission line owners typically use survey techniques to verify the sag condition of their lines.

A standard practice is to apply a fixed rating, which usually is established using a set of conservative assumptions (i.e., high ambient temperature, high solar radiation, and low wind speed), to a transmission line. In contrast, dynamic line ratings utilize actual weather and loading conditions instead of fixed, conservative assumptions. By feeding real-time data into a DLR system, the normal, emergency, and transient ratings of a line can be continuously updated, resulting in a less-conservative, higher-capacity rating of the line about 95 to

[348] EEI and NC – Edison Electric Institute and Navigant Consulting, Inc. 2010. *Transmission Projects: At a Glance*. Edison Electric Institute, Washington, D.C. Accessed July 16, 2010 at http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx (last updated February 2010).

[349] Chupka M, R Earle, P Fox-Penner, and R Hledik. 2008. *Transforming America's Power Industry: The Investment Challenge 2010-2030*. Prepared by The Brattle Group for The Edison Foundation, Washington, D.C. Accessed October 12, 2010 at http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf (undated webpage).

98 percent of the time, and increasing capacity by 10 to 15 percent.[350] In a particularly interesting twist, transmission of wind energy might become enhanced by DLR given the cooling effect of wind.[351] In a recent study conducted by San Diego Gas & Electric, they found that monitored transmission lines had 40 to 80 percent more capacity than lines using static measurements. The difference represents lost transmission capacity, and in this case lost renewable energy that had to be replaced by fossil fuel energy. Thus, DLR could improve not only the efficiency of transmission line use but also provide an environmental benefit by allowing more transmission of renewable energy when static line-rating approaches would have reduced wind output.[352]

Seppa[353] listed three approaches that were being applied to DLR in 1997—tension monitoring, surface-temperature monitoring, and weather-based ratings. A fourth, but less common, method is to measure the sag angle of the conductors with inclinometers.[354] More recent field trials also reveal some success with more direct approaches to the measurement of line sag. Seppa stated the opportunity we faced in 1999, and still face today, for the application of DLR, "…could expect to generate approximately a 10 percent increase in the real transmission capabilities—the equivalent of 10,000 GW-miles of construction—by equipping less than 10 percent of transmission lines with real-time thermal ratings systems."[355]

### A.16.2 Description of the Metric and Measurable Elements

(Metric 16.a) Number of transmission lines in the U.S. to which dynamic line ratings are applied.

(Metric 16.b) Percentage miles of transmission circuits operated under dynamic line ratings (miles).

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[350] Seppa TO. 2005. "FACTS and Real Time Thermal Rating-Synergistic Network Technologies." In *Proceedings of the 2005 Power Engineering Society General Meeting*, Vol. 3, pp. 2416-2418. June 12-16, 2005, San Francisco, California. IEEE Power Engineering Society, Piscataway, New Jersey. Accessed July 14, 2010 at http://ieeexplore.ieee.org/iel5/9893/32012/01489342.pdf (undated webpage).

[351] Oreschnick P. November 1, 2007. "Dynamic Rating Allows More Wind Generation." *Transmission & Distribution World*. Accessed July 14, 2010 at http://tdworld.com/substations/power_dynamic_rating_allows/ (last updated November 1, 2007).

[352] E Source. 2009. *Environmental Benefits of Interoperability: The Road to Maximizing Smart Grid's Environmental Benefit*. Prepared by E Source for GridWise® Architecture Council, Richland, Washington.

[353] Seppa TO. 1997. "Real Time Rating Systems." Presented at the EPRI Workshop on Real Time Monitoring and Rating of Transmission and Substation Circuits: A Technology Increasing Grid Asset Utilization. February 26-28, 1997, San Diego, California.

[354] Schneider K. 2008. Communication between Kevin Schneider (PNNL) and Mark Weimar (PNNL), "Distribution Networks Among Utilities," November 4, 2008, Portland, Oregon.

[355] Seppa TO. 1999. "Improving Asset Utilization of Transmission Lines by Real Time Rating." Presented at T&D Committee Meeting, IEEE/PES Summer Power Meeting. July 22, 1999, Edmonton, Alberta.

(Metric 16.c) Yearly average U.S. transmission transfer capacity expansion due to the use of dynamic, rather than fixed, transmission line ratings (MW-mile).

### A.16.3 Deployment Trends and Projections

The strain on our transmission system is showing, particularly as market participants and regulators are placing new requirements on the infrastructure for which it was not originally designed, such as facilitating competitive regional markets. According to DOE, 70 percent of transmission lines are over 25 years old.[356]

Trends concerning the status of our nation's transmission infrastructure are perhaps best pointed out by Hirst.[357] The U.S. transmission grid continues to grow; however, since 1982, the long-term growth of transmission transfer capacity has not kept up with the growth of peak demand. We approach the completion of a 30-year trend that is clearly shown by the numbers in Table A.19 although projections indicate that future transmission capacity will begin to match growth.

**Table A.19**. Transmission Capacity Growth and Summer Peak Demand for Four Decades[358,359]

| | Average Annual Percent Change | | | |
|---|---|---|---|---|
| | 1982-1989 | 1990-1999 | 2000-2009 | 2010-2019 |
| Transmission (miles) | 1.66% | 0.61% | 0.78% | 1.41% |
| Transmission (GW miles) | 1.94% | 0.53% | 0.44% | 2.25% |
| Summer Peak (GW) | 2.82% | 2.63% | 1.08% | 1.22% |
| MW-miles/MW demand | -0.85% | -1.70% | -0.59% | 0.93% |
| Miles/GW demand | -1.12% | -1.63% | -0.28% | 0.17% |

Clearly, technologies like DLR must be adopted if we choose to reverse this long-term trend, especially if growth projection in transmission capacity is not realized. DLR will provide an additional 10 to 15 percent transmission capacity 95 percent of the time, and fully 20 to 25 percent more transmission capacity 85 percent of the time.[360]

[356] Anderson KL, D Furey, and K Omar. 2006. *Frayed Wires: U.S. Transmission System Shows Its Age*. Special Report, Fitch Ratings.
[357] Hirst E. 2004. *U.S. Transmission Capacity: Present Status and Future Prospects*. Prepared for the Edison Electric Institute and the Office of Electrical Transmission and Distribution, U.S. Department of Energy, Washington, D.C. Accessed July 15, 2010 at http://www.oe.energy.gov/DocumentsandMedia/transmission_capacity.pdf (undated webpage).
[358] NERC – North American Electric Reliability Corporation. 2010. *Electricity Supply and Demand (ES&D) 2009*. North American Electric Reliability Corporation, Washington, D.C.
[359] Hirst 2004, Table 3.
[360] Seppa 1997.

Attempts to locate secondary sources with tabulations of the suggested measurements were unsuccessful. The number of locations where DLR is practiced appears to be small, monitoring only a fraction of the nation's transmission lines. The interviews of electricity service providers conducted for the 2011 SGSR revealed that, on average, only 0.6 percent of respondents' transmission lines were dynamically rated when weighted by the number of customers served by each respondent.

Virginia Power installed the first CAT-1[TM,361] transmission monitoring system in 1991. The Valley Group reports that two-thirds of the 30 largest utilities in North America have CAT-1 dynamic line monitoring equipment installed on their systems. However, only about half of all the utilities use the data in real time.[362]

The following is a sampling of products identified as being available, or nearly available, for installation in the nation's transmission system:

- ABB provides a wide-area monitoring system that provides thermal monitoring. The PSGuard Line Thermal Monitoring unit provides information on actual line temperature, trend in line temperature change by the second, present line resistance, line current, assessment of thermal limits, and assessment of transmission line loadability.[363]
- AREVA's MiCOM P341 enables accounting for weather conditions in calculating line ratings.[364]
- The Valley Group, Inc., CAT-1 system and related products—a cable-tension type system launched in 1991[365] and tested at locations including SDG&E.[366]

[361] CAT-1 is a trademark of The Valley Group, Inc.
[362] The Valley Group. 2010. *CAT-1 Transmission Line Monitoring System*. The Valley Group (a Nexans company), Markham, Ontario. Accessed July 15, 2010 at http://www.nexans.us/eservice/US-en_US/navigatepub_0_-17373_1673_40_4932/CAT_1_Transmission_Line_Monitoring_System.html (undated webpage).
[363] ABB. 2005. "Line Thermal Monitoring – Dynamic Rating of Transmission Lines." ABB, Baden, Switzerland. Accessed July 16, 2010 at http://library.abb.com/global/scot/scot221.nsf/veritydisplay/eace83bd6a60d884c12570d0002f99b4/$File/1002_LTM_PSGuard_Datasheet.pdf (undated webpage).
[364] AREVA T&D. 2008. *MICOM P341 and P922G*. Accessed July 16, 2010 at http://www.areva-td.com/solutions/US_437_US%3A%3ASolutions%3A%3AAutomation%3A%3AMiCOM+P341+and+P922G.html (undated webpage).
[365] The Valley Group 2010.
[366] Torre W. 1999. *Strategic Energy Research: Dynamic Circuit Thermal Line Rating.* P600-00-36. Prepared for California Energy Commission. Accessed July 15, 2010 at http://www.energy.ca.gov/reports/2002-01-10_600-00-036.PDF (undated webpage).

- Shaw Power Technologies, Inc., ThermalRate™ system—a weather-based system announced to be available in 2004 and soon to be applied by SaskPower.[367]
- EPRI Quasi-Dynamic Rating approach—a weather-based approach.[368]

The following are a few demonstration or pilot projects intended to determine the feasibility and reliability of DLR equipment operating in real time:

- The Oncor Electric Delivery Company's Smart Grid Demonstration Project in the ERCOT area of Texas. The project, using 45 load-cell tension-monitoring units and 8 master locations, will demonstrate that DLR can relieve congestion and transmission constraints, provide operational knowledge, ensure safety-code clearances aren't broken, ensure that multiple monitoring units can be integrated, and quantify/identify any operational limits. Current constraints include understanding whether DLR technology is reliable, that electricity service provider planners understand the cost and benefit structure, and the interoperability of the system with electricity service provider transmission management studies. The study area is in a critical congestion area near Dallas and is expected to be complete in 2013.[369]
- The New York Power Authority is conducting a demonstration project that evaluates instrumentation and dynamic thermal ratings for overhead transmission lines. The Electric Power Research Institute is providing their DTCR software, which provides dynamic ratings based on actual load and weather conditions. The real-time data will be provided using temperature monitors, video Sagometers, and tension monitoring equipment.[370]
- The Valley Group (TVG) reported on three demonstration projects: KCP&L congestion relief, AEP West Wind Farm Integration, and Manitoba Hydro—Avoiding Curtailment. TVG reported no curtailment of firm and non-firm contracts after the installation of real-time ratings in the KCP&L congestion relief project. In the American Electric Power (AEP) West Wind Farm Integration project, 10 to 15 percent delivery of wind power was attained. DLR

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[367] Thompson N and D Lawry. June 1, 2008. "Getting Equipped: SaskPower Uses Dynamic Rating to Increase Line Capacity." *Utility Automation & Engineering T&D*. Accessed July 16, 2010 at http://www.elp.com/index/display/article-display/331131/articles/utility-automation-engineering-td/volume-13/issue-6/features/getting-equipped-saskpower-uses-dynamic-rating-to-increase-line-capacity.html (undated webpage).

[368] EPRI – Electric Power Research Institute. 2006. "Maximize Overhead Line Ratings Through Quasi-Dynamic Rating." Electric Power Research Institute, Palo Alto, California. Accessed July 16, 2010 at http://mydocs.epri.com/docs/public/000000000001012135.pdf (undated webpage).

[369] Johnson J. 2010. "Smart Grid Demonstration Project – Dynamic Line Rating (DLR)." Presented at the ERCOT Reliability Operations Subcommittee Meeting. June 25, 2010. Accessed July 15, 2010 at http://www.ercot.com/.../05._OncorDynamicLineRatingProject06252010_.ppt (undated webpage).

[370] Mayadas-Dering J, L Hopkins, and A Schuff. 2009. "NY Utility Examines Integrating Dynamic Line Ratings." Accessed July 16, 2010 at http://www.pennenergy.com/index/power/display/366120/articles/utility-automation-engineering-td/volume-14/issue-7/features/ny-utility-examines-integrating-dynamic-line-ratings.html (undated webpage).

equipment was estimated to have deferred a $20 million line upgrade. The Manitoba Hydro—Avoiding Curtailment project reported real-time ratings above the static rating 99.9 percent of the time, and 30 percent above the static rating 90 percent of the time. The project demonstrated that DLR, as opposed to static line rating, avoided curtailment of hydroelectricity production and redispatch, which could have threatened reliability. The project also provided the electricity service provider a greater return on investment while planned upgrades remained on schedule.[371]

### A.16.3.1 Stakeholder Influences

There are numerous stakeholders that can be impacted by the successful deployment of DLR technologies, but the three primary stakeholders include

- products and services suppliers, including IT and communications – Producers of generation, control, and communications equipment that enable DLR systems are significant stakeholders.
- Transmission providers – Depending on the size and location, the insertion of DLR technologies into existing power transmission assets could enhance asset capacity and defer expensive new infrastructure investments (i.e., new transmission lines).
- end users (customers) – Successful deployment of DLR technologies will result in a power grid that has higher capacity and is more reliable. In addition, electricity customers' costs can remain low through the avoidance of costs associated with installing new transmission lines.

### A.16.3.2 Regional Influences

IOUs and transmission-only companies (TRANSCOs) have taken the lead in making investments in expanding the capacity of existing infrastructure and attempting to site and construct new infrastructure.[372] The actions of state and local regulators will continue to have a profound influence on investment decisions in whether to purchase transmission infrastructure.

No region is immune to the persistent trend in which transmission growth has been outpaced by demand growth (see Hirst[373] for details concerning this trend in each U.S. region). One can observe, however, that the WECC and Mid-Atlantic Power Pathways (MAPPs) region

[371] Aivaliotis SK. 2010. "Dynamic Line Ratings for Optimal and Reliable Power Flow." Presented at the 2010 FERC Technical Conference. June 24, 2010. Accessed July 16, 2010 at http://www.ferc.gov/EventCalendar/Files/20100623162026-Aivaliotis,%20The%20Valley%20Group%206-24-10.pdf (undated webpage).
[372] Anderson et al. 2006.
[373] Hirst 2004.

maintain their ratios of transfer capacity to peak demand up to four times higher than others. This pattern could be a result of longer transmission distances and more separated population centers in these regions compared to other U.S. locations.

## A.16.4 Challenges

Unfortunately, there are several identified barriers that may prevent or significantly reduce growth in the expanded capacity of existing transmission lines in the United States. As is similar in other industries, regulatory barriers and their economic impacts are more significant than the technical challenges in challenging deployment.

### A.16.4.1 Technical Challenges

The goal of DLR is to enable higher capacity utilization of existing transmission lines. Unfortunately, other limiting factors such as voltage instability and transient stability can also significantly affect transmission-line transfer capacity more than the thermal limitations being monitored by DLR.

Besides the equipment associated with measurements for calculating DLR, the measurement information must be communicated to system control centers. The SCADA, state estimation, and analysis applications run in the control center must have the features that take DLR information and continually refresh the alert and alarm mechanisms within the applications so that the operator is notified of potential violations and harmful situations. Typical control center applications deal with seasonal changes in line ratings, but must be augmented to accept DLR measurements.

In addition, Mayadas-Dering et al. (2009) list several technical challenges to the acceptance of DLR. These challenges include educating asset management and operations personnel in the technical aspects of DLR to gain better acceptance of the accuracy of the dynamic ratings, DLR rating variability, availability and reliability of communications links to SCADA from remote substations, and instrumentation reliability due to the vulnerability of overhead lines to extreme weather conditions.[374]

### A.16.4.2 Business and Financial Challenges

Because the grid traverses multiple regions, industries, and functions, it is challenging to obtain the necessary information on the state of the grid and to know who is responsible for coordinating and sharing responsibility for making enhancements. This leads to challenges to create incentives for investing in additional capacity.

[374] Mayadas-Dering et al. 2009.

Seppa notes a significant business barrier to acceptance of DLR—net societal benefits that don't necessarily accrue to the investor. Dynamic ratings technology benefits the whole system, but the investor doesn't necessarily obtain benefits in accordance with their costs.[375]

### A.16.5 Metric Recommendations

Inadequate data were available to quantitatively assess the suggested measurements in this metric. A small number of sites exist where DLR is practiced, and that number is growing. However, a more comprehensive interview approach with representative service providers will be needed to quantitatively identify, track, and measure the advantages achieved at those sites.

[375] Seppa TO. 2004. "Increasing Transmission Capability by Dynamic Rating of Lines and Transformers." The Valley Group, Ridgefield, Connecticut. Accessed July 16, 2010 at http://docs.cpuc.ca.gov/published/RULINGS/44759/44759Att5.ppt (undated webpage).

# A.17 Metric #17: Customer Complaints Regarding Power Quality Issues

## A.17.1 Introduction and Background

This section examines customer complaints regarding Power Quality (PQ). PQ is a simple but subjective term that describes a large number of issues found in any electrical power system. The definition of a PQ incident varies widely, depending on the customer being served. Customers are affected by PQ incidents differently according to their needs. Residential customers tend to be affected more by sustained interruptions, whereas commercial and industrial customers are troubled mostly by sags and momentary interruptions. A voltage sag, as defined by IEEE Standard 1159-1995, is a decrease in root-mean square (RMS) voltage at the power frequency for durations from 0.5 cycles to 1 minute, reported as the remaining voltage.[376] Momentary interruptions are usually just a few seconds, but can last up to a minute, whereas sustained interruptions are usually between 1 and 5 minutes.

The smart grid system has the ability to offer several pricing levels for varying grades of PQ, which is expected to give customers more choices. Currently, the standard goal for utilities in relation to power interruptions is 3 to 4 "nines." Three nines represent 99.9 percent reliability and correspond to an outage time of 8.76 hours per year while 4 nines (99.99 percent) are approximately 1 hour of downtime per year. Premium power of 6 to 9 nines (99.9999 to 99.9999999 percent) would allow only 31 seconds to 0.03 seconds of interruption per year, respectively.

For those customers who are deemed power sensitive, the extra cost of premium power would be a worthwhile investment when compared to the lost revenue from a loss of power. A smart grid will utilize advanced controls to allow for rapid diagnosis and solutions to PQ events, as well as to decrease the number of PQ disturbances from weather events, switching surges, line faults, and harmonic sources. The grid will also moderate consumer electronic loads by limiting the level of electrical current harmonics a consumer load is allowed to produce.[377]

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[376] IEEE – Institute of Electrical and Electronics Engineers. 1995. *Recommended Practice for Monitoring Electric Power Quality.* IEEE Std 1159-1995, Institute of Electrical and Electronics Engineers, Piscataway, New Jersey. Accessed October 25, 2010 at http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=475495 (undated webpage).

[377] NETL – National Energy Technology Laboratory. 2007. *A Systems View of the Modern Grid, v.2.* Prepared by National Energy Technology Laboratory for the U.S. Department of Energy, Washington, D.C. Accessed October 16, 2008 at http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/ASystemsViewoftheModernGrid_Final_v2_0.pdf (undated webpage).

### A.17.2 Description of Metric and Measurable Elements

(Metric 17) The percentage of total retail customer complaints to their service providers which are related to power quality issues (excluding outages).

### A.17.3 Deployment Trends and Projections

In the past, power-quality incidents have been rather hard to observe and diagnose because of their short interruption period. The increase in power-sensitive and digital loads has forced us to more narrowly define PQ. For example, 10 years ago a voltage sag might be classified as a drop of 40 percent or more for 60 cycles, but now it may be a drop of 15 percent for five cycles.[378]

A loss of power or a fluctuation in power causes commercial and industrial users to lose valuable time and money each year. Cost estimates of power interruptions and outages vary. A 2002 study prepared by Primen concluded that power quality disturbances alone cost the U.S. economy between $15 and $24 billion annually.[379] In 2001, EPRI estimated power interruption and power quality cost at $119 billion per year,[380] and a more recent 2004 study from LBNL estimated the cost at $80 billion per year.[381] A 2009 National Energy Technology Laboratory (NETL) study suggests that these costs are approximately $100 billion per year,[382] and further projected that the share of load from sensitive electronics (chips and automated manufacturing) will increase by 50 percent in the near future.[383]

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[378] Kueck JD, BJ Kirby, PN Overholt, and LC Markel. 2004. *Measurement Practices for Reliability and Power Quality: A Toolkit of Reliability Measurement Practices*. ORNL/TM-2004/91, Oak Ridge National Laboratory, Oak Ridge, Tennessee. Accessed November 18, 2008 at http://www.ornl.gov/sci/engineering_science_technology/eere_research_reports/power_systems/reliability_and_power_quality/ornl_tm_2004_91/ornl_tm_2004_91.html (undated webpage).

[379] McNulty S and B Howe. 2002. *Power Quality Problems and Renewable Energy Solutions.* Prepared for the Massachusetts Renewable Energy Trust, Madison, Wisconsin.

[380] Lineweber D and S McNulty. 2001. *The Cost of Power Disturbance to Industrial & Digital Economy Companies.* Prepared by Primen for the Consortium for Electric Infrastructure to Support a Digital Society, Electric Power Research Institute, Palo Alto, California. Accessed October 18, 2008 at http://www.epri-intelligrid.com/intelligrid/docs/Cost_of_Power_Disturbances_to_Industrial_and_Digital_Technology_Companies.pdf (undated webpage).

[381] Hamachi LaCommare K and JH Eto. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. LBNL-55718, Ernest Orlando Lawrence Berkeley National Laboratory, Berkeley, California. Accessed October 14, 2008 at http://certs.lbl.gov/pdf/55718.pdf (undated webpage).

[382] NETL – National Energy Technology Laboratory. 2009. *Smart Grid Principal Characteristics Provides Power Quality for the Digital Economy.* DOE/NETL-2010/1412, National Energy Technology Laboratory. Accessed June 28, 2010 at http://www.netl.doe.gov/smartgrid/referenceshelf/whitepapers/Provides%20Power%20Quality%20for%20the%20Digital%20Economy%20%28Oct%202009%29.pdf (undated webpage).

[383] NETL 2009.

It should be noted that the two latter studies outlined above include reliability costs as well as power-quality costs. Reliability costs are those associated with an unreliable supply of electricity (i.e., power outages that are either short or long in duration), whereas power-quality costs are those resulting from power fluctuations that damage equipment or otherwise result in a loss of productivity, despite the supply of electricity itself remaining constant. The cost of a momentary disruption to various users in dollars per kilowatt is shown in Table A.20 below.

**Table A.20**. Disruption Cost by Industry[384]

| | Cost of Momentary Interruption ($/kW Demand) | |
|---|---|---|
| Category | Minimum | Maximum |
| Industrial | | |
| Automobile manufacturing | $5.0 | $7.5 |
| Rubber & plastics | $3.0 | $4.5 |
| Textile | $2.0 | $4.0 |
| Paper | $1.5 | $2.5 |
| Printing | $1.0 | $2.0 |
| Petrochemical | $3.0 | $5.0 |
| Metal fabrication | $2.0 | $4.0 |
| Glass | $4.0 | $6.0 |
| Mining | $2.0 | $4.0 |
| Food processing | $3.0 | $5.0 |
| Pharmaceutical | $5.0 | $50.0 |
| Electronics | $5.0 | $12.0 |
| Semiconductor manufacturing | $20.0 | $60.0 |
| Commercial | | |
| Communications, processing | $1.0 | $10.0 |
| Hospitals, banks, civil service | $2.0 | $3.0 |
| Restaurants, bars, hotels | $0.5 | $1.0 |
| Commercial shops | $0.1 | $0.5 |

The research team conducted interviews in support of this report with 24 public, municipal, and non-profit electricity service providers. The research team asked respondents to estimate the percentage of customer complaints related to PQ issues (excluding outages). The service providers indicated that 0.6 percent of all customer complaints were related to PQ issues (this value represents a weighted average amount).

[384] NETL 2009.

In 2009, LBNL published a report that summarized the results of 28 customer value-of-service reliability studies. These studies were completed from 1989 to 2005 by 10 U.S. electricity service providers. Table A.21 summarizes the costs associated with types of power quality disturbances.

**Table A.21**. Disruption Cost by Customer Type and Interruption Duration[385]

| | Interruption Duration | | | | |
|---|---|---|---|---|---|
| | Momentary | 30 minutes | 1 hour | 4 hours | 8 hours |
| Medium and Large Commercial & Industrial | | | | | |
| Cost per Event | $11,756 | $15,709 | $20,360 | $59,188 | $93,890 |
| Cost per Average kW of Demand | $115.20 | $14.40 | $19.30 | $25.00 | $72.60 |
| Small Commercial & Industrial | | | | | |
| Cost per Event | $439 | $610 | $818 | $2,696 | $4,768 |
| Cost per Average kW of Demand | $2,173.80 | $200.10 | $278.10 | $373.10 | $1,229.20 |
| Residential | | | | | |
| Cost per Event | $2.70 | $3.30 | $3.90 | $7.80 | $10.70 |
| Cost per Average kW of Demand | $1.80 | $2.20 | $2.60 | $5.10 | $7.10 |
| Note: These cost estimates are those for interruptions occurring on summer weekday afternoons. | | | | | |

Recently, PQ has moved from customer-service problem solving to an integral part of the power-system performance process. The design of PQ devices for monitoring quality has not changed significantly in the past decade. Instead, the hardware, firmware, and software utilized by these systems has advanced dramatically. These changes are driven by market demands, standardization of measurement techniques and communication protocols, specialized large-scale integrated circuits, and improvements in software methodology. The latest PQ devices use web browsers to allow remote access of information.

#### A.17.3.1 Associated Stakeholders

There are a number of stakeholders engaged in PQ issues:

- electric service retailers working toward providing better PQ to customers
- end users (residential, commercial, and industrial users) needing consistent power quality
- regulators interested in enhancing PQ and better serving the customer base.

[385] NETL 2009.

#### A.17.3.2 Regional Influences

Regional differences surface for several reasons, such as climate, design of the distribution system, and maintenance levels; the geographical features of an area, the number and types of customers (residential, commercial, or industrial), the economic health of a region, and the fact that utilities have different distribution systems also relate to PQ problems. Therefore, interruption costs for comparable customers in different regions could vary significantly.

Also, PQ is dependent on the number and types of customers in a region. PQ-related interruption costs for a similar type of customer will differ depending on the region of the country, what industries predominate in the area, the local demographics, and the economic health of the region.

### A.17.4 Challenges to Deployment

Measuring PQ presents a challenge because of the regional influences of a given area and the inconsistency in definitions and reporting of PQ. Different geographical issues, such as weather, terrain, and demographics, create inconsistencies that make it difficult to compare PQ across regions. The PQ of electrical service is a bit more complex to measure than its reliability because PQ events are harder to observe and diagnose due to of their short duration and the fact that definitions and standards are evolving.

#### A.17.4.1 Technical Challenges

Residential, commercial, and industrial consumers will require different levels of PQ,[386] but standards organizations have not created standards for categories of PQ from which consumers can choose according to their needs. Standards for various grades of delivered power could serve as the basis for differentiated PQ pricing. Also, more distinct definitions and better reporting and handling of evolving PQ issues would help clarify the topic, which is still not well understood. Improving PQ will require enhancing the quality of power across a grid, but consumers will also increase their resilience to PQ disruptions.[387]

NETL's 2009 power quality report identified specific challenges and technologies to improve PQ across the entire smart grid. These improvements include developing premium power programs (such as setting aside specific office parks and areas for premium power usage), developing storage devices (such as superconducting magnetic energy storage) to supply PQ-sensitive consumers ultra-clean power, and deploying distributed generation devices capable of providing clean power to local sensitive loads.[388] Specifically, this requires technologies with

[386] NETL 2009, p. 20.
[387] NETL 2009, p. 17.
[388] NETL 2009, p. 13.

the ability to identify and correct the failures that result in PQ issues, such as dynamic voltage restorers, static compensators, and thyristor controlled static capacitors.[389]

#### A.17.4.2 Business and Financial Challenges

There are costs associated with implementing advanced PQ devices that some may not be willing to assume. PQ devices include those used by the utilities to monitor and diagnose problems, and devices used by the end user that depend on the size and type of the critical load. Typically, end-user devices are categorized in three groups: individual operations (controls or individual equipment protection), sensitive sub-facilities (individual circuit protection), and the entire load (at the electric-service entrance). PQ enhancing devices are still too expensive to be widely used. As more cost-effective designs are developed and supply increases in response, prices should come down. Additional cost/benefit studies would also provide a more complete accounting of the full range of benefits to the U.S. economy resulting from improving PQ.[390]

FERC, in a policy statement on matters related to bulk power-system reliability, stated that public electricity service providers may be uncertain about spending significant amounts of money without reassurance they will be able to recover it. The report goes on to note that:

*Regulators should clarify that prudent expenditures and investments to maintain or improve bulk power system reliability will be recoverable through rates. The Commission also assures public utilities that they will approve applications to recover prudently incurred costs necessary to ensure bulk electricity system reliability, including prudent expenditures for vegetation management, improved grid management and monitoring equipment, operator training, and compliance with NERC reliability standards and Good Utility Practices.*[391]

### A.17.5 Metric Recommendations

Customer sentiment regarding PQ issues is captured by measuring PQ complaints by customers as a percentage of total complaints. What constitutes a PQ complaint, however, is unfortunately open to interpretation, and it is advisable that such thresholds be established early so that progress can be quantified. Such thresholds or measurements for PQ could potentially be established by a collaborative effort between stakeholders identified in this report and relevant government agencies. Consideration should also be given to constructing a more clear definition of what constitutes a PQ complaint. In developing this definition, the

[389] NETL 2009, p. 13.
[390] NETL 2009, p. 24.
[391] FERC – Federal Energy Regulatory Commission. April 19, 2004. *Policy Statement on Matters Related to Bulk Power System Reliability*. Docket No. PL04-5-000. Federal Energy Regulatory Commission, Washington, D.C. Accessed October 14, 2008 at http://www.ferc.gov/whats-new/comm-meet/041404/E-6.pdf (undated webpage).

research team should work closely with electric-service retailers and subject-matter experts. Further, the number of interviews should be expanded to generate a more precise assessment of this metric. Finally, future reports should consider reporting the total number of PQ complaints while also noting the total number of complaints reported by the interviewed utilities; reporting the total number of PQ complaints would enable a better understanding of the magnitude of the issue.

To provide different grades of power to consumers, a shift in standards must occur. PQ standards have not been well defined in the past and currently only provide a safety net. By implementing standards for the level of PQ customers expect to receive, it would be easier to differentiate between grades of power, thus giving end users more choices.

# A.18 Metric #18: Cyber Security

## A.18.1 Introduction and Background

The interconnected North American grid is arguably the world's largest and most complex machine. It has achieved and sustained an enviable record of reliability through application of numerous technological and operational efficiencies and regulatory oversight. The grid's complexity and interconnected nature, however, also pose a significant drawback; under the right circumstances, problems occurring in one area have the potential to cascade out of control and affect large geographical regions.

Economic forces and technology development are making the power system more dependent on information systems and external communications networks. The interconnected nature of the communications systems that support regional and interregional grid control, and the need to continue supporting older legacy systems in parallel with newer generations of control systems, further compound these security challenges.[392] Additionally, with the advent of inexpensive microcontrollers and smart grid implementation, there is a growing trend for increased intelligence and capabilities in field equipment installed in substations, within the distribution network, and at the customers' premises. This increased control capability, while vastly increasing the flexibility and functionality to achieve better economies, also introduces new cyber-vulnerabilities that have not previously existed.

## A.18.2 Description of Metric and Measurable Elements

An understanding of component and associated system vulnerabilities will be necessary to quantify cyber-security issues inherent in smart-grid deployments, particularly when these elements can be used to control or influence the behavior of the system. Assessments will be needed, both in controlled laboratory or test-bed environments and in actual deployed field conditions, to explore and understand the implications of various cyber-attack scenarios, the resilience of existing security measures, and the robustness of proposed countermeasures. Vendor adoption of these countermeasures will be critical to broadly influence the installed base of future deployments. The asset-owner utilities will remain responsible for legacy systems.

[392] NERC – North American Electric Reliability Corporation. 2009a. *Implementation Plan for Version 3 of the Cyber Security Standards CIP-002-3 through CIP-009-3*. North American Electric Reliability Corporation, Princeton, New Jersey. Accessed July 13, 2010 at http://www.nerc.com/docs/standards/sar/V3_Implementation_Plan_Redline_last_posting_2009Nov19.pdf (undated webpage).

(Metric 18) The electric power industry's compliance with the North American Electric Reliability Corporation Critical Infrastructure Protection (CIP) standards (Table A.22).

Designed to maintain the integrity of North America's interconnected electrical systems, the NERC CIP standards establish minimum requirements for cyber-security programs protecting electric control and transmission functions. On January 17, 2008, FERC directed NERC to further tighten the standards to provide for external oversight of classification of critical cyber assets and removal of language allowing variable implementation of the standards. Version 2 of the CIP Standards is now effective. Version 3 revisions were based on FERC feedback and as raised by industry in the Standard Authorization Request (SAR) on Version 2 and await FERC approval.[393] For Version 4 standards, at the time of writing this report, the drafting team was reviewing comments received from the informal comment period.[394]

**Table A.22**. Summary of the NERC Critical Infrastructure Protection Standards CIP 002-009[395]

| NERC Standard | Subject Area |
|---|---|
| CIP-002 | Critical Cyber Asset Identification |
| CIP-003 | Security Management Controls |
| CIP-004 | Personnel & Training |
| CIP-005 | Electronic Security Perimeter(s) |
| CIP-006 | Physical Security of Critical Cyber Assets |
| CIP-007 | Systems Security Management |
| CIP-008 | Incident Reporting and Response Planning |
| CIP-009 | Recovery Plans for Critical Cyber Assets |

**Table A.23**. Summary of the NERC Critical Infrastructure Protection Standards CIP 010-011 (Emerging)[3]

| NERC Standard | Subject Area |
|---|---|
| CIP-010 | BES Cyber System Categorization |
| CIP-011 | BES Cyber System Protection<br>BES Cyber System Categorization |

CIP 002-4 has now become CIP 010-1, and CIP-003-4 through CIP-009-4 were consolidated into CIP-011-1.

[393] NERC – North American Electric Reliability Corporation. 2008. *Project 2008-06, Cyber Security Order 706*. North American Reliability Corporation, Princeton, New Jersey. Accessed July 13, 2010 at http://www.nerc.com/filez/standards/Project_2008-06_Cyber_Security.html (undated webpage).

[394] NERC – North American Electric Reliability Corporation. 2010a. *Reliability Standards: Critical Infrastructure Protection (CIP)*. North American Reliability Corporation, Princeton, New Jersey. Accessed July 13, 2010 at http://www.nerc.com/page.php?cid=2%7C20 (undated webpage).

[395] NERC 2010a.

### A.18.3 Deployment Trends and Projections

The implementation schedule for entities responsible for the reliability of the North American bulk electricity systems was established in the revised implementation plan for cyber security standards CIP-002-1 through CIP-009-1. During the schedule, these entities will undergo a process of identifying and protecting critical cyber assets that effect and/or control the reliability of the bulk electricity systems.[396]

The aforementioned implementation schedule established various deadlines for when responsible entities were required to become substantially compliant, compliant, and auditably compliant with each standard. Responsible entities that were mandated to register during 2006 were required to become auditably compliant by December 31, 2010. Balancing authorities, transmission operators, and reliability coordinators, including those coming into compliance with NERC's Urgent Action Cyber Security Standard 1200 (UA 1200), were required to become auditably compliant by the end of the second quarter of 2010.

Enforcement of the standards has identified a lack of compliance and, therefore, violations. Identified violations are being reported to the date on which the violation was found to occur. From 306 CIP violations in July 2008, the number of CIP violations decreased to 54 in January 2010 and continued to decline through May 2010 (Figure A.50). As violations are found, they are attributed to past time periods based on the deemed date of the violation. Thus, past values can be adjusted upward over time as new violations are discovered. The enforcement of standards and the subsequent corrections are expected, over time, to lead to fewer and fewer violations as companies take steps to increase compliance.

[396] NERC – North American Electric Reliability Corporation. 2009b. *(Revised) Implementation Plan for Cyber Security Standards CIP-002-1 Through CIP-009-1*. North American Reliability Corporation, Princeton, New Jersey. Accessed July 13, 2010 at http://www.nerc.com/fileUploads/File/Standards/Revised_Implementation_Plan_CIP-002-009.pdf (undated webpage).

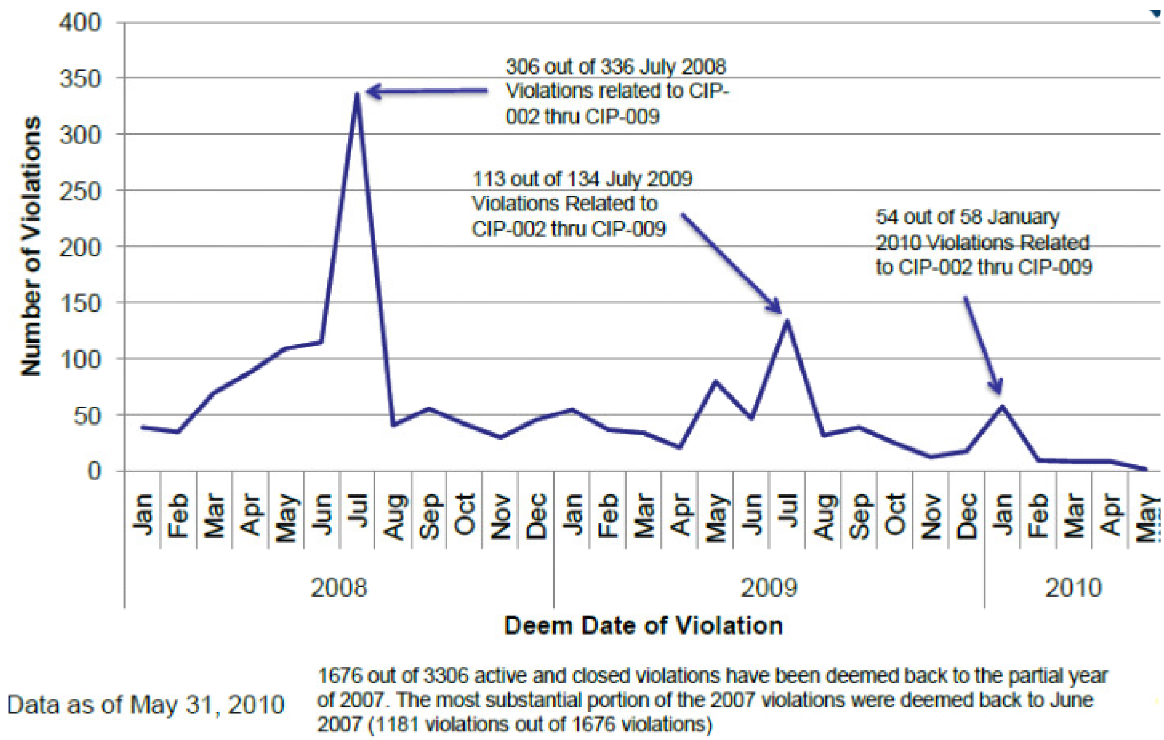


**Figure A.50**. Deemed Date Trend for Active and Closed Violations[397]

As of May 31, 2010, five out of eight CIP 002-009 standards were part of the Top 10 most violated standards among the FERC Enforceable Standards (Figure A.51). Among the Top 10 NERC active and closed violations, two are CIP 002-009 standards. CIP 004 – Personnel and Training ranks third in the list, as shown in Figure A.52.

[397] NERC – North American Electric Reliability Corporation. 2010b. *Compliance Trending – May 2010*. North American Reliability Corporation, Princeton, New Jersey. Accessed July 18, 2010 at http://www.nerc.com/files/Compliance%20Violations%20Statistics%20-%20May%202010.pdf (last updated June 29, 2010).

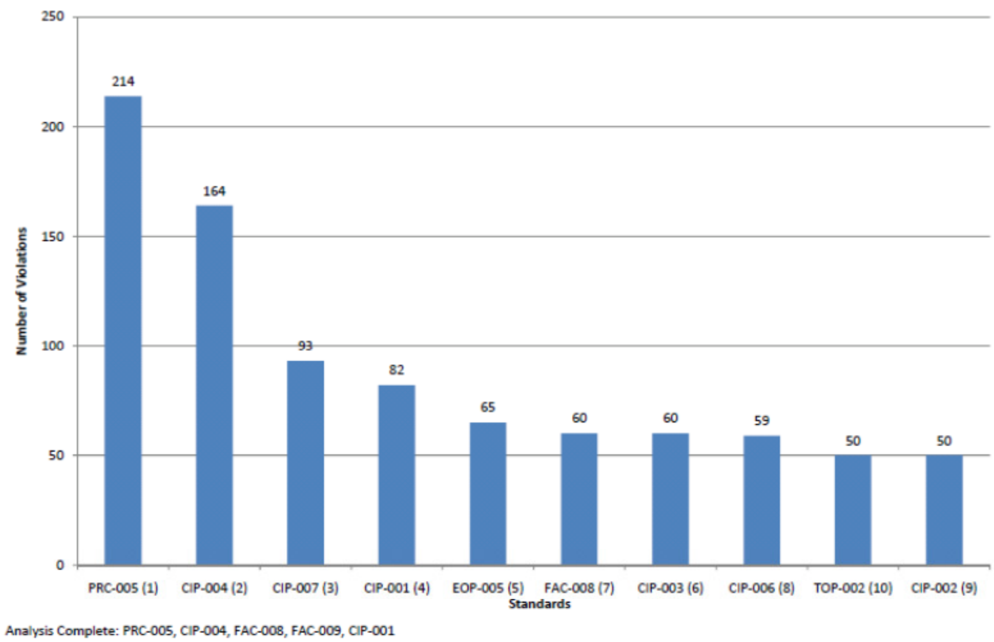


**Figure A.51**. Top 10 Most Violated Standards among the FERC Enforceable Standards Rolling 12 Months from June 1, 2009 through May 31, 2010

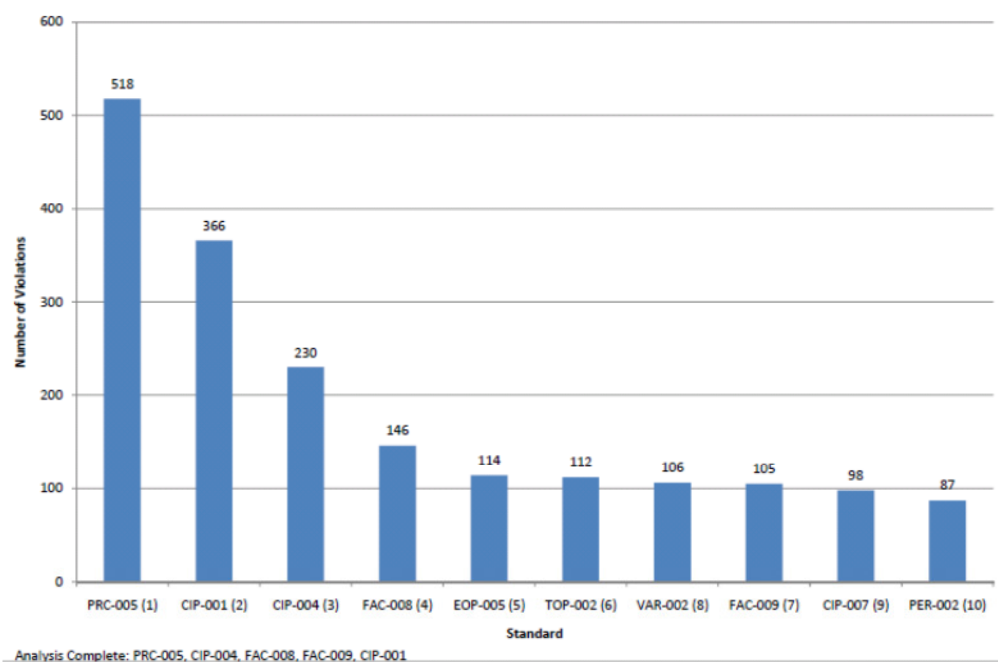


**Figure A.52**. Top 10 All Time Violated Standards: Active + Closed Violations through May 31, 2010[398]

[398] NERC 2010b.

**Table A.24**. NERC and Regional Top 10 most Violated Standards, Rolling 12 Months: May 1, 2009 to April 30, 2010 – Summary Table[6]

| Region | Violation Bank | | | | | | | Key: NERC top 1-5 NERC 6-10 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| NERC | PRC-005 229 | CIP-004 168 | CIP-007 88 | CIP-001 82 | EOP-005 65 | CIP-003 55 | FAC-008 54 | CIP-006 53 | FAC-001 44 | CIP-002 44 |
| FRCC | PRC-005 | CIP-004 | EOP-005 | CIP-007 | EOP-001 | BAL-005 | PER-002 | FAC-008 | CIP-005; FAC-001 TOP-002 | |
| MRO | PRC-005 | PRC-008 | FAC-003 | FAC-001 | CIP-007 | EOP-005 | COM-002 | CIP-004 | PER-002 EOP-008 CIP-006 CIP-003 | |
| NPCC | CIP-004 | CIP-001 | CIP-006 | PRC-005 | FAC-009 | FAC-008 | TOP-002 | FAC-001 FAC-003 PRC-008 TOP-003 VAR-002 | | |
| RFC | PRC-005 | CIP-004 | CIP-007 | CIP-006 | CIP-005 | CIP-003 | FAC-008 | VAR-002 | PRC-001 | CIP-008 CIP-009 |
| SERC | CIP-004 | PRC-005 | EOP-005 | CIP-007 | CIP-001 | VAR-002 | CIP-006 | CIP-002 | CIP-005 | CIP-009 |
| SPP | PRC-005 | CIP-004 | FAC-001 | CIP-003 | CIP-007 | CIP-009 | FAC-008 | FAC-009 | PRC-008 | CIP-002 |
| TRE | FAC-008 | PRC-005 | PRC-008 | CIP-001 | CIP-004 | FAC-003 | IRO-001 | PRC-011 | TOP-001 | |
| WECC | PRC-005 | EOP-005 | CIP-001 | TOP-002 | CIP-004 | CIP-007 | PER-002 | EOP-001 | CIP-003 | COM-001 |

From Table A.24, we see the trend in NERC Top 10 violations across the NERC regions. It can be seen that all regions have CIP 004 in their list of Top 10 violations in the rolling 12 months ending April 20, 2010. The RFC region has 7 out of the 8 CIP 002-009 standards in its list in this table.[399] Figure A.53 shows the ranking of CIP-004 in the list of the Top 10 violated standards for all the NERC regions. This ranking is for the rolling 12 months May 1, 2009 to April 30, 2010.[400]

[399] NERC 2010b.
[400] NERC 2010b.

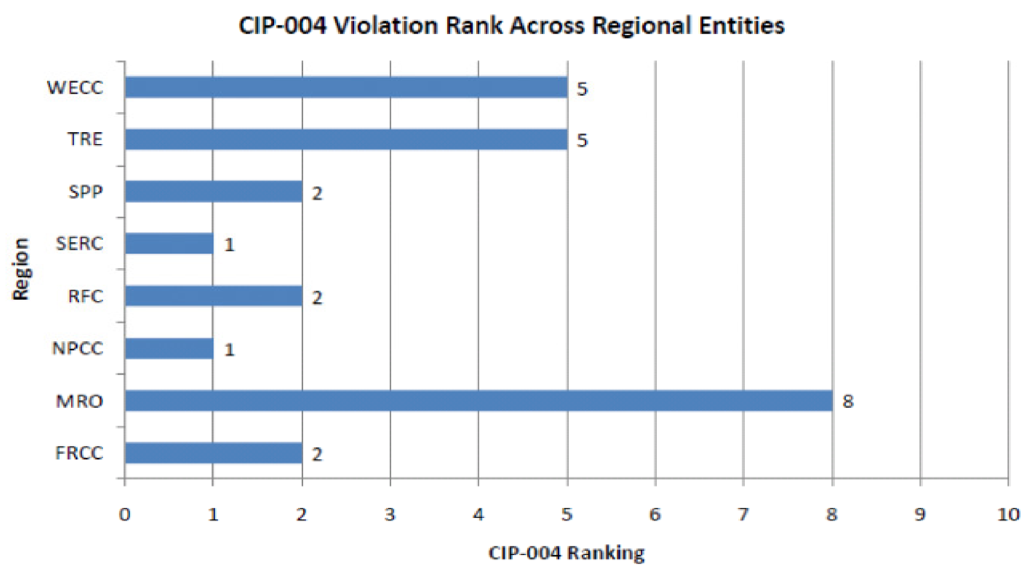


**Figure A.53**. NERC and Regional Top 10 most Violated Standards, Rolling 12 months: May 1, 2009 to April 30, 2010 – CIP-004 Ranking across Regions[401]

The interviews of 24 electricity service providers (Appendix B) included a question about specific security measures that utilities are implementing. The results are shown in Table A.25. Of those electric service providers interviewed for this study, 62.5 percent deploy intrusion detection technologies, while 50 percent have key management systems, 66.7 percent encrypted communications, and 91.7 percent have firewalls established to secure their systems.

**Table A.25**. Security Question from Electricity Service Provider Interviews

| Have you deployed the following security features? (*Select all that apply)* | Affirmative Response |
|---|---|
| a. Intrusion detection | 62.5% |
| b. Key management systems | 50% |
| c. Encrypted communications | 66.7% |
| d. Firewalls | 91.7% |
| e. Others | 12.5% |

While compliance with mandatory security standards is an important step toward achieving security, it is in itself not a complete measure of security. Generally, these security standards are more focused on compliance requirements, and increased compliance may not necessarily equate to increased security. Furthermore, standards can take years to develop and implement and may lag behind the cutting edge of technology deployment, particularly when the industry

401 NERC 2010b.

is in transition, as is the case with smart grid technologies. Therefore, these metrics may be more of a lagging rather than leading indicator of the security posture of the smart grid.

Control systems evolved in an environment of implicit trust. A properly formatted command is carried out without question by the automatic controller. In this environment, security relies on isolation. Over the years, the electricity service provider industry built and operated its own private communications infrastructure to control the electric power grid, using systems and protocols unique to the industry. Noise, interference, and equipment reliability were primary issues to overcome. This isolation resulted in a belief that the system was inherently secure, but was expensive to implement and maintain and did not easily avail itself to adoption of new technologies. Because of this, the trend has been shifting toward the use of shared communication with public networks, open and commonly used protocols, and general-purpose operating systems whose many security weaknesses are more widely known. Economic forces and technology development are making the power system more dependent on information systems and associated communications networks, particularly in the context of smart grid systems and their inclusion of demand-side resources. The interconnected nature of these communications systems and the need to continue supporting older legacy systems in parallel with newer generations of control systems further compound the complexity and challenges of addressing this problem.[402]

In addition, data exchange interactions between businesses result in handing off data security responsibility at the interface between the interacting parties. Ensuring that information privacy is protected and that cyber-security vulnerabilities are addressed on either side of an interface requires a coordination of business processes, particularly when the data may transition to different technologies and protocols. Designed-in security approaches are only now emerging.

Unlike the threats from component failures, extreme weather, or natural disasters that are mitigated by highly effective and well-developed contingency and restoration practices, the cyber-threat landscape is only beginning to be effectively addressed through common industry standards and best practices.

#### A.18.3.1 Associated Stakeholders

- End users – Cyber-security breaches can greatly affect consumers, not only from disruptions when the electric infrastructure is compromised, but also because a smart grid incorporates participation by consumers' automation systems. Electricity-related information-technology connectivity may provide a new path for a cyber attack that might affect a facility's operation or obtain private information. Each consumer group needs to assess its vulnerability and develop an appropriate security posture.

[402] NERC 2010b.

- Electric service retailers and wholesale electricity traders – These entities connect to customer systems, market operators, and infrastructure system operators with greater linkages as smart grid trends progress. Security issues must be assessed across their operations with cooperation between all transacting business systems.
- Distribution and transmission service providers, balancing authorities, and reliability coordinators – The protection of the infrastructure is a national concern. The NERC CIP requirements, while modest, are being refined with recognition of the importance of security.
- Products and services suppliers – Information technology, business systems, and engineering vendors have shown interest in developing or updating product offerings to address security needs. However, real change occurs when customers specify security features as requirements for their purchases.
- Energy policymakers and advocates – The idea that the electric infrastructure could be crippled by a cyber-security breach is disconcerting to those protecting the public interest. Policymakers are searching for ways to ensure that cyber-security issues are addressed. For example, FERC is pushing NERC to strengthen the CIP standards, as the balance between cost, risk, and effective measures continues to mature.

#### A.18.3.2 Regional Influences

Approaches to cyber security should not vary greatly across nations, on a technical basis, relative to hardware and software. State-specific issues may arise because of different laws relating to transparency of information associated with Freedom of Information Act issues. For example, in California, a state-sponsored organization such as the California Independent System Operator may find it difficult to protect sensitive information from being disclosed because of state sunshine laws. There will also continue to be international and national standards in the cyber-security area that may compete in technology and policy approaches.

### A.18.4 Challenges to Deployment

#### A.18.4.1 Technical Challenges

The electricity system of the future could become much more vulnerable to disruption by skilled electronic intrusion originating either internally or externally. Compounding the problem, security is often neglected or introduced as an afterthought rather than being incorporated as a core component in the development and deployment of these new technologies and applications.

Because cyber security is largely a defensive practice when applied to protecting against a steady flow of active exploits, the threat to computer and control systems is never completely ameliorated. A vital need in the electricity industry is the development of new approaches for inherent security—components and systems with built-in security capabilities. Coordination is also needed between these approaches and techniques appearing in other industrial, commercial building, and residential systems that interact with the electricity system. Resources, such as adequately trained staff to design and implement the standards, will present challenges in the first few years.[403]

The complexities and interdependencies of cyber security elements are poorly understood. These include internal and external issues with the electricity infrastructure. Examples of internal interdependencies are market-based systems for buying, selling, and wheeling (transferring power across lines not owned by the generator) power throughout the network; while they are not directly connected to the control systems providing real-time operation of the grid, there are sometimes subtle dependencies that could cause reliability implications if security in these systems were compromised. An example of an external interdependency is reliance on other infrastructures, such as communication, that are vital to the operation of the electricity infrastructure. Systemic failures that propagate among these dependency seams can create failure modes that are difficult to predict and mitigate.

Finally, it is not clear whether there is general consensus among the industry stakeholders regarding the threat, which leads to inconsistent views about the appropriate level of attention and investment needed to achieve appropriate levels of security.

#### A.18.4.2 Business and Financial Challenges

The key challenge will be to maintain reliability in a vastly more "connected" electric industry under threats that could involve multiple, distributed, and simultaneous or cascading incidents—whether accidental or deliberate. Steps should be taken to enhance the security of real-time control systems using sound information security practices. In the future, the goal for all control systems for critical applications should be that they are designed, installed, operated, and maintained to survive an intentional cyber assault with no loss of critical function.

All stakeholders share a common interest in deterrence, intrusion detection, security countermeasures, graceful degradation, and emergency backup and rapid recovery. While the NERC CIP-002 through CIP-009 standards are an effective start to begin addressing cyber security and are achieving increased awareness and action within the electricity service

[403] Dyonyx. 2009. *Top Ten Compliance Issues for Implementing the NERC CIP Reliability Standard*. Accessed July 19, 2010 at http://www.dyonyx.com/white_papers/Top%20Ten%20Issues%20for%20Implementing%20the%20NERC%20CIP%20Reliability%20Standard.pdf (undated webpage).

provider industry, there is growing recognition, based on NERC's reporting of noncompliance, that they have not yet achieved their ultimate purpose—defining uniform standards that, if implemented, can provide adequate security against cyber threats to the electric infrastructure. Problems with the standards include provisions for entities to self-define what they will protect and how they will protect it; this has resulted in a patchwork of mitigation measures that is more focused on compliance than security. In addition, there is concern that the standards have loopholes associated with communications and certain types of control systems. Given the evolving nature of the technologies involved and the nascent deployment of the processes, there is a constant need to keep updating and moving to newer versions of the standards, as has been the case. More work to transition the industry mindset from a culture of compliance to a culture of security may be necessary.

Another issue is inconsistent regulatory support that electricity service providers have associated with cost recovery for necessary security enhancements. The electricity regulatory landscape is complex with multiple stakeholders at the federal, state, and local levels. Not all regulatory jurisdictions have recognized security as a recoverable cost, and other electricity service providers are constrained in implementing security because it would cause pre-existing rate cases to be reopened at great expense and risk to the company. Other issues include public versus private electricity service provider ownership, small numbers of very large utilities and large numbers of small utilities, and widely varying regulation.

### A.18.5 Recommendations for Future Measurement

Newer versions of the NERC CIP standards are evolving and their implementations are being planned. The audit results are also being reported on a monthly basis, which makes the nationwide trends in deployment easy to assess. Hence, it would be beneficial to stay with this trend of constant standards evolution and timely audit results reporting. In using NERC CIP compliance results, care should be taken to realize that the results do not include many of the utilities and other organizations implementing smart grid solutions. Only those participating directly in the bulk power system are represented by these metrics.

In addition to the NERC CIP standards, efforts specifically focused on cyber security for smart grid implementation have been underway for the past few years. For example, the NIST/Smart Grid Interoperability Panel Cyber Security Task Group has produced NIST-IR 7628, "Guidelines for Smart Grid Cyber Security." Version 1.0 of this three-volume report was issued in August 2010 and can be used as a source for future SGSRs.

A more mature evaluation of cyber security will evolve toward self-assessment or possibly third-party certified tools to provide enduring capabilities for vendors, system integrators, and asset owners to afford appropriate security commensurate with the risk associated with the application. This will empower industry to be responsible for making reasoned and informed tradeoffs. Metrics related to this may include surveys of the distribution-level utilities having a cyber security compliance program, the inclusion of cyber security requirements in vendor solicitations, and so forth.

Fundamentally, systems will be required that are inherently secure and robust. Research and development will be needed to develop these systems. Metrics to measure their effectiveness will need to be defined.

# A.19 Metric #19: Open Architecture/Standards

## A.19.1 Introduction and Background

The vision for the smart grid hinges on the ease of integration of intelligent equipment and systems to enable their collaboration and coordination to achieve local, regional, and national energy objectives. Given the abundance of such components, the information-technology integration approach must be scalable and the connectivity agreements in an area, such as integrating building resources with the electricity system, must converge to a few commonly supported practices. Though such practices will change as technology solutions advance, commercially viable approaches will consider a measured level of stability for interface definitions that support legacy systems and the introduction of new technology. The term "open" is intended to mean that the specification, approach, or resource that facilitates system integration is accessible to all interested parties without unreasonable barriers to entry.

While direct measures of openness or standards adoption are difficult obtain, one promising approach is to use concepts derived from the Carnegie Mellon Software Engineering Institute and the software Capability Maturity Model (CMM®).

Widespread adoption of openly available standards and architectural approaches is an indication of maturity in technology and business practices. A smart grid, with its diverse stakeholders, represents a relatively immature movement composed of many parties, each with its own heritage in business practices and standards. A convergence of approaches may come from the large penetration of Internet-based technology and methodology, but it will take time to develop and materialize. The development of software in general experienced a similar situation; there were many methods, languages, and processes for developing software in different communities, with different levels of success. Rather than pick a "winner," the Software Engineering Institute (SEI) at Carnegie Mellon took the approach of encouraging a culture of continuous process improvement. The result is the SEI Capability Maturity Model for Software, and subsequently, the CMM Integration (CMMI).[404]

The concept is to develop a smart grid interoperability maturity model (SGIMM) for application to communities of organizations engaged in smart grid product and project implementations. The model facilitates developing methods and processes that improve the integration and maintenance of the automation devices and systems. In addition, the model can be used to create tools for self-evaluation, resulting in recommendations for improving

[404] SEI – Software Engineering Institute. 2010. *CMMI Related Topics: Frequently Asked Questions.* Software Engineering Institute, Carnegie Mellon University, Pittsburgh, Pennsylvania. Accessed October 14, 2008 at http://www.sei.cmu.edu/cmm/ (undated webpage).

interoperability.[405] The SGIMM could build upon other programs and works, including the CMMI[406] and the National E-Health Transition Authority (NEHTA)[407] work.

### A.19.2 Description of Metric and Measurable Elements

(Metric 19) Interoperability Maturity Level—the weighted-average maturity level of interoperability realized among electricity system stakeholders.

The SGIMM model defines the following levels:

Level 5 – Optimizing:

**Continually improve processes based on quantitative understanding of the causes of variation**: Exchange specifications in an interoperability area are based on standards with planned upgrade processes driven by quantitative feedback from implementations and the needs of the community.

Level 4 – Quantitatively Managed:

**Quantitative objectives for performance measurement and management:** Processes for appraising the effectiveness of the specifications and standards used in an interoperability area are in place and supported by the community. Successes and deficiencies are noted. Implementations are certified interoperable.

Level 3 – Defined:

**Quantitative objectives for performance measurement and management:** Exchange specifications in an interoperability area are defined and use standards adopted by the community. Well-developed interoperability verification regimes are in place. Participants claim standards compliance.

Level 2 – Managed:

**Planned & executed in accordance with policy:** Exchange specifications and testing processes exist in an interface area on a project basis, but are not defined for the community. Some standards referenced or emerging, but may not be consistently applied.

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[405] Widergren S, A Levinson, and J Mater. 2010. "Smart Grid Interoperability Maturity." In *Proceedings of the 2010 PES General Meeting*. July 25-29, 2010, Minneapolis, Minnesota. IEEE Power & Energy Society, Piscataway, New Jersey.

[406] SEI 2010.

[407] NEHTA – National E-Health Transition Authority Ltd. March 26, 2007. *Interoperability Maturity Model, v.1.0*. National E-Health Transition Authority Ltd., Sydney, Australia. Accessed September 24, 2010 at http://www.nehta.gov.au/component/docman/doc_download/220-interoperability-maturity-model-v10 (undated webpage).

Level 1 – Initial:

**Ad hoc & chaotic:** Unique, custom-developed interface area. Requires significant custom engineering to integrate with other components. No agreed-upon standards between parties. Interoperability is difficult to achieve and very expensive to maintain.[408]

The method for measuring progress in open architecture and standards is to develop the SGIMM and then survey interactions between stakeholders to measure the interoperability maturity level in specific smart-grid areas that emphasize the interfaces between organizational boundaries. Examples of these boundaries include interfaces between the electricity service provider and residences, commercial buildings, and industrial plants; another is the interface between a balancing authority and a reliability coordinator.

### A.19.3 Deployment Trends and Projections

The scope of the smart grid includes the connectivity that occurs in the transmission and distribution areas (such as substation automation), the control centers (such as SCADA information sharing with other applications and between operating organizations), and the consumer-side resources (such as commercial equipment and distributed generation and storage). Efforts have been underway for some time to integrate equipment and systems in substation automation, control centers, and enterprise systems, and within industrial, commercial-building, and residential energy management systems. The level of integration is increasing in each of these areas, and the amount of integration between these areas is also increasing.

Under EISA of 2007, NIST has "…primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems…."[409] In November 2009, NIST formed the Smart Grid Interoperability Panel (SGIP) and encouraged smart grid stakeholders from all organizations associated with electric power to establish this community to advance interoperability through goals, gap analysis, and prioritized efforts to improve the challenges to integration.[410]

NIST has worked to foster an open and regular means of collaboration among domain experts with the common goal of advancing smart grid interoperability. In April 2009, NIST awarded a contract to EPRI to facilitate two stakeholder workshops. Following a series of

[408] Widergren et al. 2010.
[409] NIST – National Institute of Standards and Technology. 2010. *NIST Framework and Roadmap for Smart Grid Interoperability.* NIST Special Publication 1108, National Institute of Standards and Technology, Gaithersburg, Maryland. Accessed July 16, 2010 at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf (undated webpage).
[410] Widergren et al. 2010.

stakeholder workshops, NIST issued Special Publication 1108, *the Smart Grid Interoperability Framework and Roadmap for Smart Grid Interoperability Standards Release 1.0.* This document identified 75 standards that can be applied or adapted to smart grid interoperability or cyber security needs and identified priority action plans to address 16 standardization gaps and issues.[411]

NIST has identified the following five foundational families of standards, which are fundamental to smart grid interoperability:

- IEC 61970 and IEC 61968: Provide a Common Information Model (CIM) necessary for exchanges of data between devices and networks, primarily in the transmission (IEC 61970) and distribution (lEC 61968) domains.
- IEC 61850: Facilitates substation automation and communication as well as interoperability through a common data format.
- IEC 60870-6: Facilitates exchanges of information between control centers.
- IEC 62351: Addresses the cyber security of the communication protocols defined by the preceding IEC standards.

In addition to the *Smart Grid Interoperability Standards Roadmap*, EPRI is also developing the IntelliGrid Architecture, which is an approach for enabling interoperability between products and systems through the integration of data networks and equipment. The program is designed to provide a methodology, tools, and recommendations to electricity service providers for standards and technologies when deploying systems including distribution automation, demand response, wide-area measurement, and advanced metering.[412]

Standards and openness are also advancing in terms of the layers of agreement that must align. The GridWise Architecture Council (GWAC) was formed to engage stakeholders and create a maturity model that can define and evaluate the process for system-wide interoperability (Widergren et al. 2010). The SGIMM proposes three major categories that need to be aligned to achieve interoperability: technical, informational, and organizational. Figure A.54 represents a simplified version of the SGIMM, and is illustrating the three framework categories and the general goals for each interoperability issue (configuration and evolution, operation, security and safety). In addition, the framework identifies eight interoperability categories and ten issue areas that cut across the interoperability categories. This model will help stakeholders as they focus on specific areas of concern.

[411] NIST 2010.

[412] EPRI – Electric Power Research Institute. 2004. *IntelliGrid Architecture*. Electric Power Research Institute, Palo Alto, California. Accessed July 24, 2010 at http://www.epri-intelligrid.com/intelligrid/techdev/intelligrid/intelligrid.html (undated webpage).

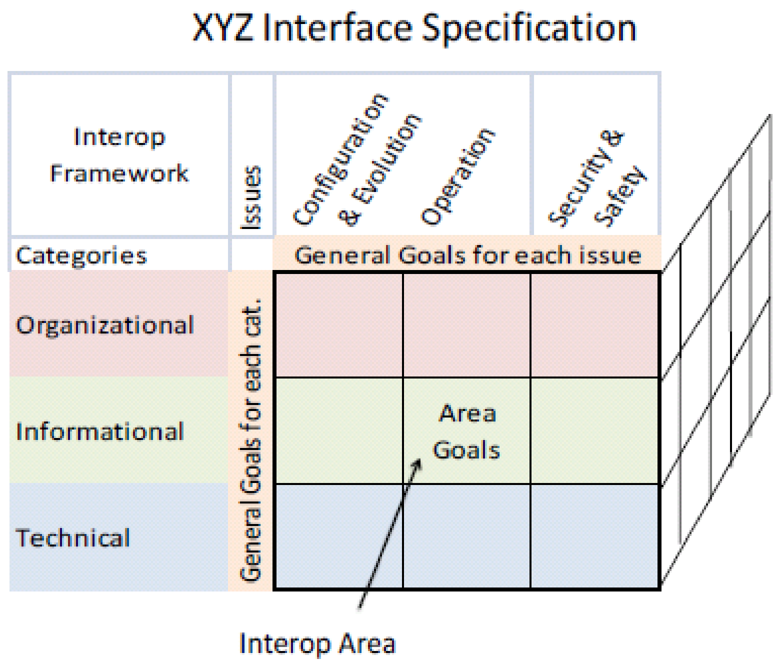


**Figure A.54**. Interoperability Categories (from GWAC Interoperability Context-Setting Framework)[413]

In addition, the framework identifies ten cross-cutting issue areas that establish a two-dimensional landscape to help people focus on specific concerns. To simplify and provide a high-level view of this landscape, the cross-cutting issues are proposed to be collected into three issue areas:

- Configuration & Evolution:
  - Shared Meaning of Content
  - Resource Identification
  - Discovery & Configuration
  - System Evolution & Scalability
- Operation:
  - Time Synchronization & Sequencing
  - Transaction & State Management
  - Quality of Service
- Security & Safety:
  - Security & Privacy

[413] Widergren et al. 2010.

- Logging & Auditing
- System Preservation.[414]

The model enables the user to focus attention on the high level or the detailed level of analysis. To dig deeper into interoperability areas, the category and issue axes can be used to guide users to more specific issues.[415]

The technical categories involve network connectivity and syntax. Though there are many lower-level protocols to handle communications networks (e.g., cable, twisted pair, fiber optics, wireless, broadband power line carrier), and protocols with associated syntax (e.g., Ethernet, TCP/IP, Zigbee, IEEE 802.11, Wi-Fi), the standards for these technologies are mature to the point that an assortment of communications products are now procured and integrated to support many applications. Layered on top of these communications networks are general-purpose application protocols to support SCADA activities. Each business community has developed its own SCADA-like protocols to meet its performance and cost requirements. In each community the trend has been to move away from proprietary communications networks, protocols, and syntax, toward widely available standards supported by various product offerings.

The informational categories are less mature than those in the technical area. The SCADA information models tend to generically describe equipment, measurements, and actuators. The understanding of the equipment and how it fits within a business process is held in specification documents and the minds of the programmers and integrators. Thus, there is a high level of customization for each application. Anything approaching standardization is contained in best practices and the knowledge gained through experience. Exceptions to this exist with a few automation interface standards. However, the standards emerging to support eCommerce are making significant progress with modeling the information (semantics) for specific business contexts. The Internet-based information-modeling standards (e.g., XML, UML, Resource Description Framework [RDF], and Web Ontology Language [OWL]) dominate the new standards work, while earlier approaches to information modeling continue to progress and evolve based upon the familiarity of developers in targeted communities.

The organizational categories involve business operations and strategic decision-making. In this area, business processes are modeled using methodologies that are supported by enterprise integration and eCommerce tools and modeling techniques. These methods represent humans and machines as abstract concepts that reflect the series of actions involved in a business process. Where each human or machine application interfaces with another, the sequence, performance, information exchanged, and consequences under failure scenarios are

[414] Widergren et al. 2010.
[415] Widergren et al. 2010.

captured in a specification. Languages continue to evolve to record these specifications and mechanically turn appropriate aspects of them into software-interface definitions and code. In particular, web services and service-oriented architecture techniques are being employed to support these higher-level concepts. Business-process modeling is virtually nonexistent in consumer-side electricity-related automation and T&D automation. It is appearing in control centers, particularly as the interface to other applications of the enterprise.

In the technical categories of network connectivity and syntax, multiple standards will continue to evolve to support the various communications media; however, bandwidth is becoming less of a problem and Internet-based approaches are likely to continue to grow as hardware and software tools make them more cost-effective.

Convergence toward information modeling using UML, XML Schema, and the OWL semantic language is gaining ground. With the advent of web services and service-oriented architecture, tools, and techniques for designers and implementers are making it easier to move into business-process modeling.

#### A.19.3.1 Stakeholder Influences

As Figure A.54 suggests, nearly all stakeholders are affected by the availability and adoption of integration architectures and supporting standards. In particular, the following groups are most affected:

- consumers – The amount and reliability of participation of demand-side resources depends on integrating automation systems cost effectively.
- electric service retailers – Aggregating demand-side resources for participation in local and area system operations depends on cost-effective automation systems to coordinate with consumer systems.
- distribution and transmission service providers – Cost-effective and reliable techniques require standards. Given the scale and long life of the equipment, approaches must be able to evolve over time and continue to integrate with legacy components.
- balancing authorities, generators, wholesale electricity traders, market operators, and reliability coordinators – These require standard enterprise-integration approaches and eCommerce standards for connectivity.
- products and services suppliers – The maturing modularization of software systems discourages large, proprietary solutions that inhibit future competition with other suppliers. Standards are more commonly put into specifications. In addition, suppliers can be more competitive by integrating their offering with components provided by other suppliers. Less customization can allow for higher levels of productivity.

- regulators and policy makers – Greater levels of standardization and common integration approaches can bring costs down for the consumer and foster competition.

#### A.19.3.2 Regional Influences

Given the global reach of solutions providers, open architecture and standards should be encouraged internationally. Practically speaking, national-standards bodies will probably continue to have differences from their counterparts across the globe, in particular, USA, EU, Japan, China, and India. With few exceptions, the leading IT standards in use and being developed apply uniformly to all parts of a nation.

### A.19.4 Challenges

#### A.19.4.1 Technical Challenges

Architectures and standards are subjects of innovation through better ideas. While agreement and adoption of standards eases integration and enables cost-effective implementation, new approaches can bring greater capability and further cost reductions. Features that focus on interfaces and that support extensions, versioning, and adaptation to old and newer technologies can help support the need to evolve in the quickly changing world of technology. The NIST Priority Action Plans have identified the need for new standards and several standards development organizations are actively developing these to fill the gaps in enabling smart grid interoperability. Although these standards are evolving, there is a need to test and validate the application of these standards to realize the interoperability potential envisioned.

#### A.19.4.2 Business and Financial Challenges

Flexibility is important in picking an architectural approach and associated standards. At the corporate level, a heterogeneous mixture of technologies and standards service an enterprise and its business-partner connections. A balance must be found among many factors, including the cost to move to new technology and standards, the ability to support multiple standards, the impact on productivity and competitiveness, and the risk associated with a decision. Return on investment is the traditional mechanism to explore these trade-offs; however, it can be difficult to quantify the returns from moving toward solutions that manage risk and offer future alternatives.

### A.19.5 Metric Recommendations

Future measurements of progress in this area will depend on the further development of the SGIMM, its deployment, and later, interviews with stakeholders about smart grid applications to investigate the interoperability maturity level in specific areas of interaction. The development of the SGIMM should identify and include objective criteria and available standards for each of the cross-cutting issues, and interfaces between the domains. Once developed, the SGIMM should be implemented and made available to stakeholders to assess their level of interoperability readiness using a standardized approach.

# A.20 Metric #20: Venture Capital Investment in Smart Grid Startup Companies

## A.20.1 Introduction and Background

Historically, electricity service providers have been conservative when adopting new and emerging technologies. Regulatory barriers and the lack of direct incentives have at times failed to foster the development of technologies that enhance energy efficiency. When considering investment in smart grid technologies, utilities are also challenged by the nascent stages in which these technologies often exist, and the lack of industry standards for them.

Venture capital played a major role in creating the biotechnology enterprise, the information technology market, and the communications industry. In recent years, venture capital firms have invested increasingly in smart-grid-technology providers. These venture capital firms have noted several investment drivers, including

- high oil prices making energy delivery by electricity service providers more costly—the price of oil is recognized as a major indicator of prices in the energy sector, even though oil only produces a small fraction of the electricity in the U.S.
- energy infrastructure in need of updating and replacement
- shrinking capacity margins forecast over the long-term
- increasing recognition of clean and efficient technologies.

Investors have increasingly concluded that these drivers point toward a future that will include smart grid and demand-response technologies, and that those who invest early could be well rewarded.[416]

Investing in companies focusing on smart grid applications has paid significant dividends to some investors. Figure A.55 demonstrates that the stock performance of a small number of companies developing demand-response technologies that support the smart grid outperformed the Dow Jones Utility Average Index in the January 2004 to September 2007 time period.[417] The companies highlighted in Figure A.55 include Itron, Inc., ESCO Technologies, Inc., Televent Git S.A., Badger Meter, Inc. (BMI), and Roper Industries, Inc.

[416] Quealy JS. 2007. "Financial Market Assessment of Demand Response's Future." In *Southern California Edison Demand Response Forum*, Global Energy Partners, LLC, Lafayette, California. Provided by author to researchers for this report.
[417] Quealy 2007.

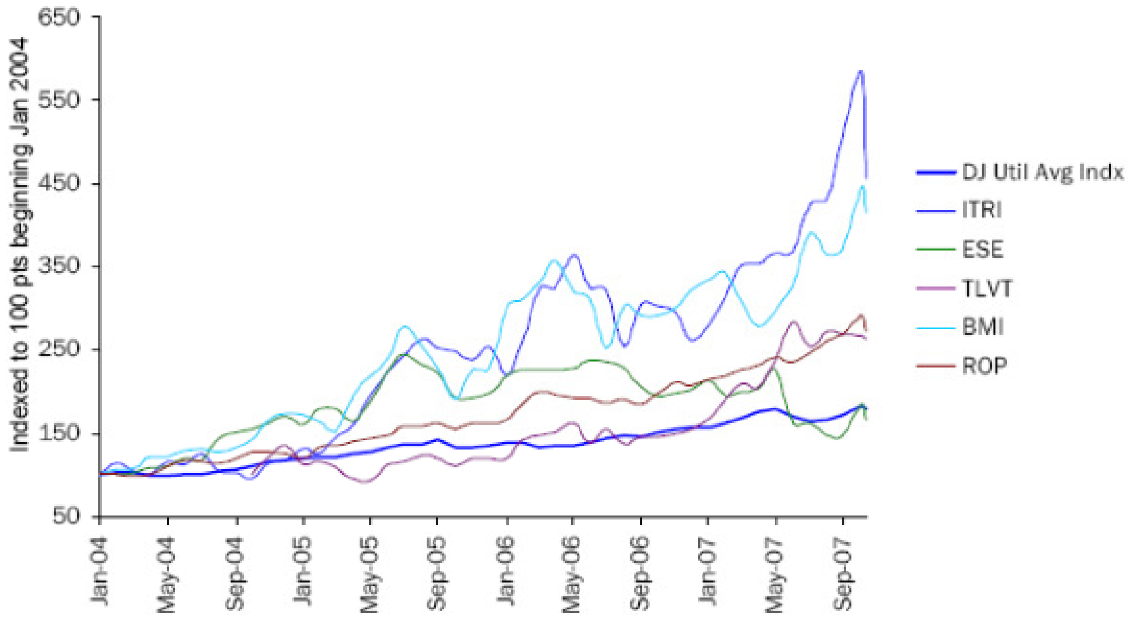


**Figure A.55**. Stock Performance of Companies Developing Smart Grid Technologies

In addition to venture capital funding, organizations in both the public and private sectors are recognizing the importance of allocating portions of their budgets to R&D. Such investment, including funding for specific smart grid programs, has increased in recent years due to interest and promotion of energy efficiency, renewable energy, and advanced grid technology programs.

### A.20.2 Description of Metric and Measurable Elements

(Metric 20a) The total annual venture capital funding of smart grid startups located in the U.S.

### A.20.3 Deployment Trends and Projections

In recent years, investment in smart grid technologies has gained traction. In 2009 alone, numerous venture capital deals were announced, including

- SynapSense Corporation received $7 million for the development of wireless energy efficiency solutions and data centers.
- Silver Spring Networks, which is a wireless smart grid equipment and software developer, received $15 million.
- Tendril, Inc. secured $30 million toward the development of smart grid software and wireless sensors.
- Powerit Solutions received $6 million to support development of electric transformer cores.

- OutSmart Power Systems, Inc., secured $2 million to develop hardware and software systems designed to monitor and manage energy usage and other commercial building activities.

The research team secured venture capital data for the smart grid market for 2000 through 2009 from the Cleantech Group LLC. The Cleantech Group's database includes detailed information at the company level. For each transaction, the amount of the transaction, the name of the company, and the company's focus were identified. Transactions were stratified by year. Based on the data presented by the Cleantech Group, venture-capital funding secured by smart grid startups was estimated at $194.1 million in 2007 and $414 million in 2009.[418,419] In total, the Cleantech Group identified deals totaling more than $1.6 billion during the 2000 to 2009 timeframe.

Data provided by the Cleantech Group were used to construct Figure A.56. Annual venture capital funding levels are presented along with a two-period moving average line. As shown, venture-capital funding of startups slumped between 2000 and 2002, but has since rebounded, growing from $58.4 million in 2002 to $414.0 million in 2009. Between 2002 and 2009, venture capital funding of smart grid startups grew at an average annual rate of 32.3 percent. While growth in smart grid venture capital investment was robust during the 2002 to 2009 time period, a cautionary note is needed as global investment in clean technologies, including smart grid, dropped in the second half of 2010 with venture capital investment in the third quarter down by 30 percent compared to the second quarter of 2010 and 11 percent compared to the third quarter of 2009. In the fourth quarter of 2010, global investment in clean technologies declined for the second consecutive quarter by an additional 17 percent compared to the third quarter of 2010.

[418] Fan B. 2008. Email from Brian Fan (Cleantech Group) to Patrick Balducci (Pacific Northwest National Laboratory), "Smart Grid Request," September 10, 2008, Portland, Oregon.
[419] Cleantech Group, LLC. 2010. *Press Releases*. Accessed September 20, 2010 at http://cleantech.com/about/pressreleases/ (undated webpage).

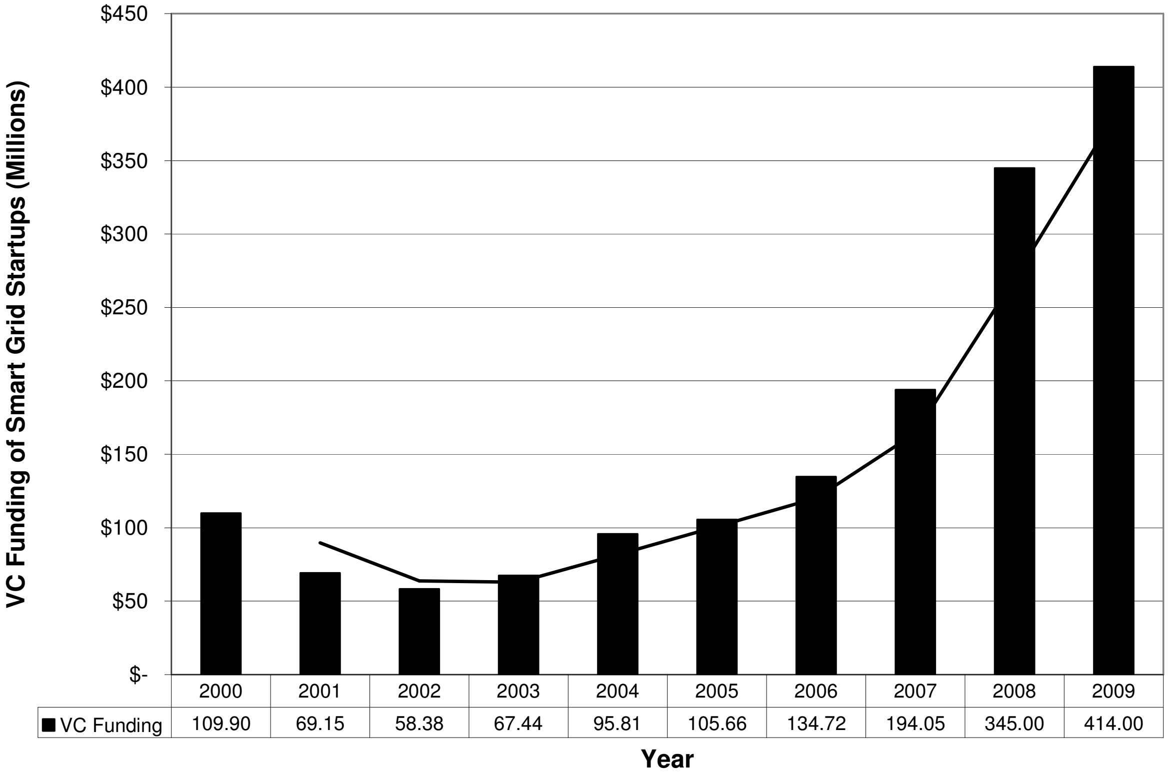


**Figure A.56**. Venture Capital Funding of Smart Grid Startups (2000 to 2009)

In a report recently prepared by the Cleantech Group for the DOE, venture capital spending for the 2007 to 2010 timeframe was allocated to companies by the types of services they provide. The analysis conducted by the Cleantech Group found that more than 50 percent of the venture capital spending in the smart grid space during the 2007 to 2010 timeframe went to metering companies (Figure A.57). Home energy management companies received 20 percent of all venture capital spending and building energy management companies received 18 percent during the 2007 to 2010 timeframe.[420]

[420] Neichin G and D Cheng. 2010. *2010 U.S. Smart Grid Vendor Ecosystem: Report on the Companies and Market Dynamics Shaping the Current U.S. Smart Grid Landscape*. Cleantech Group LLC.

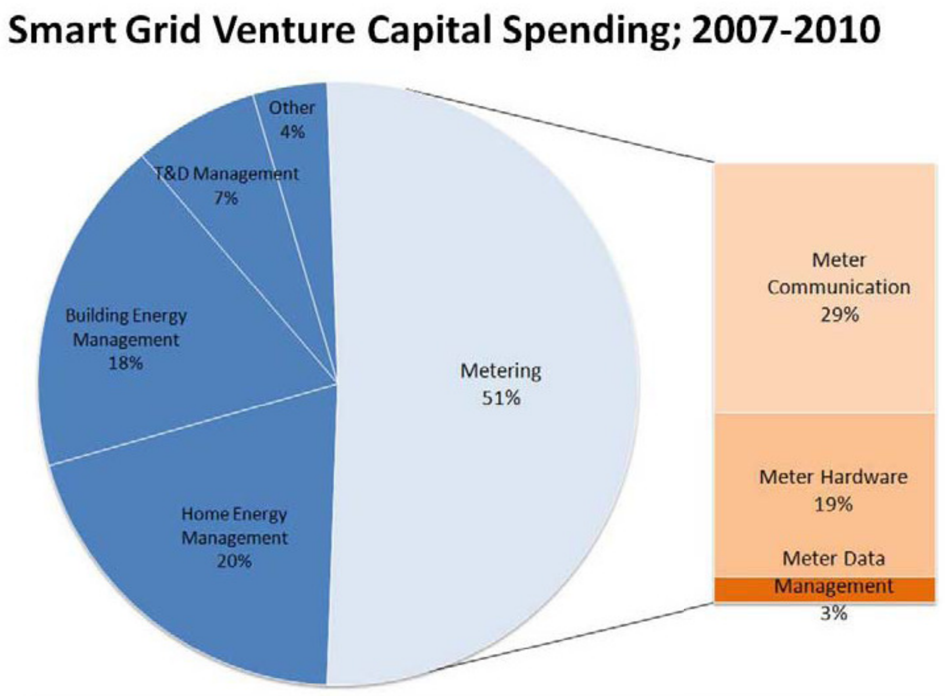


**Figure A.57**. Venture Capital Spending by Company Type (2007 to 2010)

Venture capital is only one source of R&D funding of smart grid companies. Public and private agencies across the U.S. are increasingly investing in the development of smart grid technologies. Since 2004, implementation of renewable portfolio standards, interest in energy efficiency and smart grid technology development have helped to encourage enhanced energy R&D budgets. One study estimated global public investment in smart-grid-specific R&D programs during 2009 to be $530 million, led by the U.S., Italy, and Japan.[421]

In 2009, ARRA designated $4.5 billion in funding for electric grid modernization programs, including $3.4 billion for the SGIG program. To date, ARRA has resulted in grants being awarded to 99 recipients, including private companies, service providers, manufacturers and cities, with total public-private investment amounting to over $8 billion.[422] Figure A.58 maps projects that are currently underway, including both ARRA and non-ARRA smart grid demonstration projects. These projects, along with other recent initiatives at the state level and within private industry, are lighting a path towards the development of new and innovative smart grid-enabled products, services, and markets.

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[421] IEA – International Energy Agency. 2010. *Global Gaps in Clean Energy RD&D: Updates and Recommendations for International Collaboration*. International Energy Agency, Paris, France. Accessed August 10, 2010 at http://www.iea.org/papers/2010/global_gaps.pdf (undated webpage).

[422] DOE – U.S. Department of Energy. August 4, 2009. "Obama Administration Announces More than $327 Million in Recovery Act Funding for Science Research." U.S. Department of Energy, Washington, D.C. Accessed July 28, 2010 at http://www.energy.gov/news2009/7737.htm (last updated August 4, 2009).

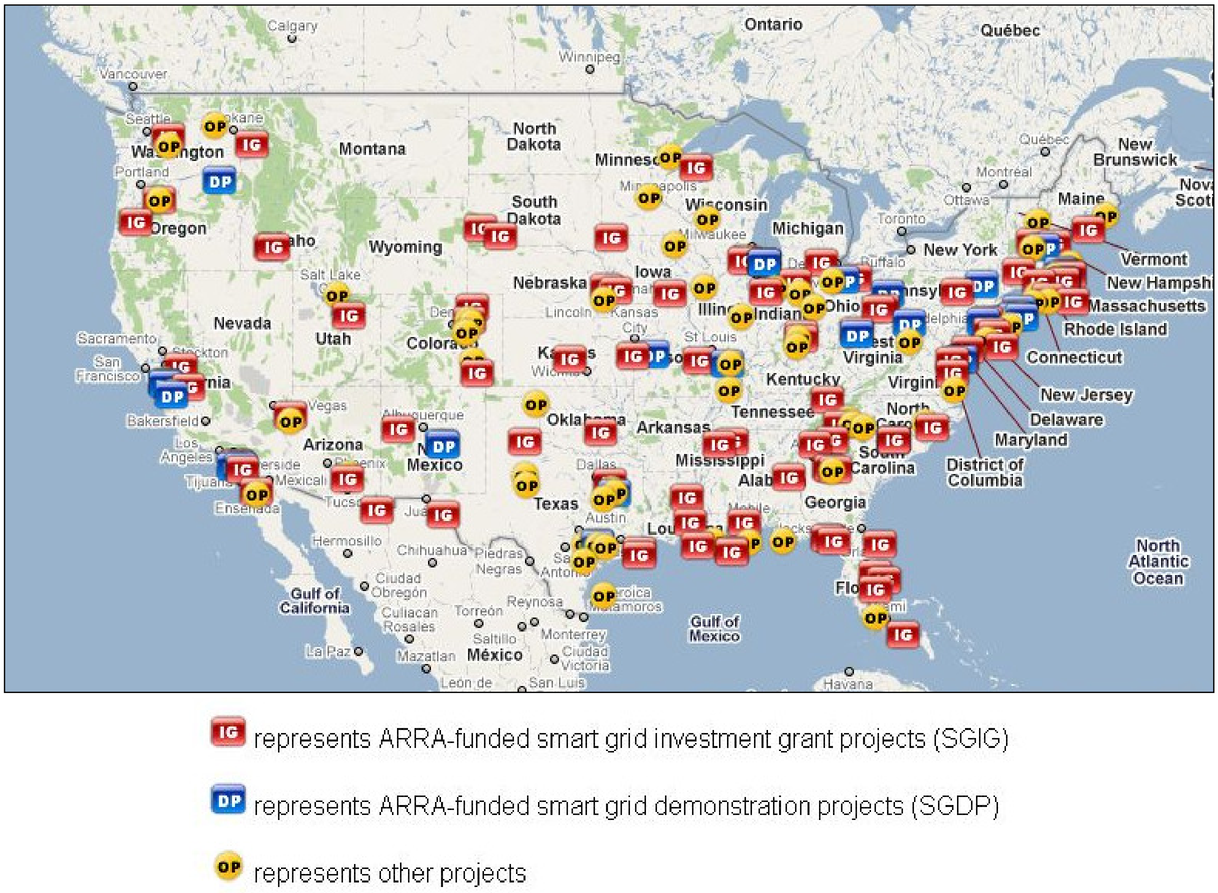


**Figure A.58**. ARRA and Non-ARRA Smart Grid Investment and Demonstration Projects[423]

In addition to federal stimulus spending, contributions to smart grid R&D include many non-profit organizations, companies, utilities, and commissions. One such organization is EPRI, which has allocated $15.6 million to R&D projects taking place in 2010.[424] Projects include grid operations, planning, distribution, energy storage, demand response, distributed renewable generation, and PHEV grid integration. In addition, the California Energy Commission has appropriated $83.5 million to R&D annually as legislated through Senate Bill 1250.[425] R&D projects include demand response, renewable energy development and advanced grid technology research.

[423] SGIC – Smart Grid Information Clearinghouse. 2010. *Smart Grid Projects*. Accessed September 23, 2010 at http://www.sgiclearinghouse.org/?q=node/13 (undated webpage).
[424] EPRI – Electric Power Research Institute. 2010. *Smart Grid*. Electric Power Research Institute, Palo Alto, California. Accessed July 28, 2010 at http://mydocs.epri.com/docs/Portfolio/PDF/2010_PDU-VP3.pdf (undated webpage).
[425] CEC – California Energy Commission. 2010. *Research, Development, and Demonstration*. Accessed July 29, 2010 at http://www.energy.ca.gov/research/# (last updated June 15, 2010).

### A.20.3.1 Associated Stakeholders

There are a number of stakeholders whose actions impact the funding of smart grid startups:

- regulatory agencies considering smart grid and demand response business cases
- policymakers interested in using smart grid technologies to offset future peak-demand growth and reduce the need for investment in supply-side infrastructure.
- residential, commercial, and industrial customers who may be skeptical of demand-response and smart grid technologies and their effect on future costs and power reliability
- electric service providers interested in reducing peak demand and encouraging load shifting
- product and service suppliers in private industry interested in capitalizing on opportunities with smart grid technologies
- venture capital and other investment funds interested in riding the wave of the new technology while yielding potentially significant returns on their investment.

### A.20.3.2 Regional Influences

Regional influences are reflected both in the presence of programs (e.g., time-of-use pricing, advanced metering) and in regulatory structures that advance smart grid investment. The locations of companies engaged in smart grid investment also influence the development of the smart grid. With respect to AMI, which is a major driver in smart grid investment, there are major investment programs underway at a number of utilities:

- PG&E, which operates in California, has invested $466 million to install 5.8 million gas and electric meters by June 2010; full deployment is projected by 2012.[426]
- DTE Energy, operating in Michigan, invested $84 million to install 0.7 million smart meters in their service area in 2010.[427]
- American Electric Power, which has a large service area in the Midwest and South, plans to install up to 5 million meters, with regulatory approval, through their gridSMART program by 2015. Regulatory support has been approved for deployment of 1.25 million meters in

[426] CPUC – California Public Utility Commission. March 12, 2009. "CPUC Authorizes PG&E to Upgrade its SmartMeter Program." Press Release. Accessed June 15, 2010 at http://docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/98459.htm (undated webpage).

[427] DTE Energy. October 27, 2009. "DTE Energy SmartCurrents Program Awarded $84 Million DOE Grant." News Release. Accessed June 17, 2010 at http://dteenergy.mediaroom.com/index.php?s=43&item=453 (last updated October 27, 2009).

Texas, Ohio, and Oklahoma, and the deployment will be completed in 2014. Total investment will top $375 million for the Texas, Ohio, and Oklahoma regions.[428]

- Southern California Edison aims to install 5 million AMI meters by 2012.[429]
- CL&P will offer dynamic pricing programs through AMI to 1.2 million customers beginning in 2012.[430]

In addition to AMI, the majority of customers enrolled in TOU programs are located in the eastern United States in a region stretching from Indiana to New Jersey, and states located to the west of the Rocky Mountains. Smart communication thermostats are being deployed in California, Maryland, New Jersey, and Texas. T&D automation is being employed or is under development by Oncor (Texas), Centerpoint Energy (Texas), The Southern Company (Georgia), the Tennessee Valley Authority, and ConEdison (New York).[431] Each of these deployments represents an opportunity for smart grid startups.

The geographic distribution of the opportunities to install smart grid technologies has correlated with the location of smart grid startups. Figure A.59 presents a map of the U.S. and identifies the locations of the headquarters for 137 of the top 177 smart grid companies recently identified by the Cleantech Group.[432] While smart grid companies are largely concentrated in New York, California, and Massachusetts, smart grid companies are dispersed throughout the U.S.—there are such companies located in 30 of the 50 states.

[428] AEP – American Electric Power. 2010. *A Climate of Change: Our Progress, Our Future*. Accessed June 15, 2010 at http://www.nxtbook.com/nxtbooks/aep/accountability2010/#/2 (undated webpage).

[429] SCE – Southern California Edison. Undated. "Edison's Smarter Meter." *Southern California Edison Backgrounder*. Accessed October 11, 2010 at http://www.sce.com/NR/rdonlyres/4BDCBE35-697E-49C6-9773-C49A019E6FD3/0/SCEsSmarterMeter.pdf (undated webpage).

[430] CL&P – Connecticut Light & Power. March 31, 2010. "CL&P Recommends Smart Meters and New Pricing Options for All Customers Beginning in 2012." Press Release. Accessed September 24, 2010 at http://nuwnotes1.nu.com/apps/mediarelease/clp-pr.nsf/0/248C6DEF20FC767C852576F5006C4493?OpenDocument (undated webpage).

[431] Silverstein A. 2008. *The Smart Grid and the Utility of the Future.* Gulf Coast Power Association, Missouri City, Texas. Accessed October 14, 2008 at http://www.gulfcoastpower.org/default/silversteinmay2008.pdf (undated webpage).

[432] Cleantech Group 2010.


**Figure A.59**. Locations of Smart Grid Companies in the U.S.

Regional influences of R&D spending are most evident in demonstration projects funded by ARRA. As illustrated in Figure A.58 (located in the Deployment Trends and Projections section), the demonstration programs are currently taking place primarily in the Northeast and on the West Coast. Examples of such programs are illustrated below:

- New York State Electric & Gas Company is conducting a smart grid storage demonstration project in Binghamton, New York. Objectives of the program include development of an innovative smart grid control system for a Compressed Air Energy Storage System (CAES) using an existing salt cavern. The project will receive $29.5 million in ARRA funding.[433]
- SustainX, Inc. will receive an ARRA award for $5.4 million to build an electricity-service-provider-scale, low-cost CAES in West Lebanon, New Hampshire. Objectives include integration of renewable generation systems to the grid.[434]
- Amber Kinetics Inc., in conjunction with the Lawrence Livermore National Laboratory, was awarded $4 million to integrate flywheel technologies into grid-connected energy storage systems. The project is located in Fremont, California.[435]

[433] SGIC 2010.
[434] SGIC 2010.
[435] SGIC 2010.

In addition, a variety of demonstration projects are being undertaken by energy providers and private companies around the nation. Programs include virtual power plant demonstrations, AMI/dynamic pricing pilot projects, and microgrid demonstrations. In the private sector, companies such as GE and IBM are teaming with venture capital firms to promote smart grid development. GE's Ecomagination Challenge is awarding $200 million to selected participants who submit winning ideas for grid efficiency, renewable energy, and ecohomes/ecobuildings.[436] Similarly, IBM's SmartCamp global contests are funding small companies and entrepreneurs who submit proposals for innovative technology development.

## A.20.4 Challenges to Deployment

There are a number of technical and business/financial barriers to implementing smart grid technologies; these barriers could stall investment in these technologies.

### A.20.4.1 Technical Challenges

Technical barriers include:

- It is too early to pick a technological winner in many smart grid areas, and the lack of a dominant technology generates risk for investors.
- There is presently a patchwork approach to the development of smart grid alternatives, thus preventing rapid technology change and adoption.
- Electricity service providers have historically been more focused on supply-side solutions and many of the smart grid technologies support demand-side alternatives.
- Consumers are often confused by, and distrustful of, smart grid alternatives offered by utilities (e.g., advanced meters, real-time pricing, appliances that communicate with the grid).

### A.20.4.2 Business and Financial Challenges

Business and financial barriers include:

- The ultimate timing in terms of smart grid technology adoption rates presents a risk to investors who are unwilling to wait 10 to 20 years for an ultimate payoff.
- Regulatory barriers discourage investment in smart grid technologies.
- Utilities are incentivized in many cases to continue using traditional means of power supply to maximize their own return on investment.

[436] GE – General Electric. 2010. *Ecomagination Challenge: Powering the Grid*. Accessed January 5, 2011 at http://challenge.ecomagination.com/ct/a.bix?c=ideas (undated webpage).

- Utilities operate in markets with little or no competition, so innovation is not ultimately required, due to a lack of competing technologies.

### A.20.5 Metric Recommendations

The definitions of a smart grid company differ between the firms that track venture capital funding. More consideration should be given to defining what constitutes a smart grid startup, and this definition should be developed, refined, and ultimately held constant over time to allow for trend analysis.

# A.21 Metric #21: Grid-Connected Renewable Resources

## A.21.1 Introduction and Background

A smart grid can be instrumental in allowing grid-connected renewable electricity to provide a significant portion of electricity production. In a carbon-constrained world, the environmental benefits provided by electricity generated from renewables will help reduce the carbon footprint of the electricity generating sector, as renewable resources emit significantly lower amounts of $CO_2$, or none. Coal-fired electricity generation produces almost 213 pounds of $CO_2$, while natural-gas-generated electricity produces 117 pounds per million BTUs of energy generated. Renewables, on the other hand, produce relatively small quantities of $CO_2$ with only geothermal, at 16.6 pounds, and municipal solid waste (MSW), at 91.9 pounds per million BTUs, emitting any $CO_2$, as reported by the EIA.[437] Currently about 3 percent of U.S. electricity production is generated by other renewable energy resources as defined by EIA.[438,439,440] Conventional hydroelectric is excluded from this metric because it is considered baseload power.

The net benefits that accrue to smart grid applications may, however, be a fraction of the total emissions avoided due to total renewable electricity production. A recent report by PNNL indicates that smart grid applications could allow additional renewable electricity production to reduce annual $CO_2$ emissions by 5 percent by 2030.[441] The relatively small amount of emissions in comparison to total avoided carbon emissions occurs because a significant portion of intermittent renewable electricity generation can occur with a very small change in the amount of ancillary services required. The PNNL report indicates that until intermittent generation reaches 20 to 25 percent, only a 0.1 percent increase in regulation is required, along with an increase in spinning reserves margin from 5 to 7 percent of load.

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[437] EIA – Energy Information Administration. 2010a. "Table A.3: Carbon Dioxide Uncontrolled Emission Factors." *Electric Power Annual with Data for 2008*. Energy Information Administration, Washington, D.C. Accessed October 25, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (last updated January 21, 2010).

[438] Kreutzer D, K Campbell, W Beach, B Lieberman, and N Loris. 2010. *A Renewable Electricity Standard: What it Will Really Cost Americans*. CDA10-03, The Heritage Foundation, Washington, D.C. Accessed June 18, 2010 at http://www.heritage.org/Research/Reports/2010/05/A-Renewable-Electricity-Standard-What-It-Will-Really-Cost-Americans (undated webpage).

[439] EIA – Energy Information Administration. 2010b. "Figure ES 1: U.S. Electric Power Industry Net Generation." *Electric Power Annual with Data for 2008*. Energy Information Administration, Washington, D.C. Accessed June 18, 2010 at http://www.eia.doe.gov/cneaf/electricity/epa/figes1.html (last updated January 21, 2010).

[440] Conventional hydroelectric production was not included because of its baseload nature. The "Other Renewables" category does include small, distributed hydroelectricity production.

[441] Pratt RG, MCW Kintner-Meyer, PJ Balducci, TF Sanquist, C Gerkensmeyer, KP Schneider, S Katipamula, and GJ Secrest. 2010. *The Smart Grid: An Estimation of the Energy and $CO_2$ Benefits*. PNNL-19112 Rev 1, Pacific Northwest National Laboratory, Richland, Washington. Accessed October 12, 2010 at http://energyenvironment.pnl.gov/news/pdf/PNNL-19112_Revision_1_Final.pdf (undated webpage).

However, alternative approaches to smart grid deployment indicate that all renewable-produced electricity and especially intermittent resources require smart grid functions today to allow their effective integration. Those smart grid technologies include forecasting and communicating the forecasts for intermittent resource generation on multiple time horizons including day-ahead and hour-ahead forecasting to transmission system operators, local utilities, and customers.[442]

### A.21.2 Description of Metric and Measurable Elements

The three metrics for grid-connected renewable resources reflect two important aspects of renewable-resource electricity production—the portion of total electricity generated from renewable resources and the amount of carbon dioxide avoided. Metrics 21.b and 21.c provide a range for the amount of carbon emissions reduced, based on less strict and more strict interpretations of smart grid enabling requirements for the integration of renewable resource electricity.

*(Metric 21.a) Renewable electricity as a percent of total electricity, both in terms of generation and capacity.* The metric is based on the grid-generated other-renewable electricity production and capacity, divided by total grid generation and summer capacity. The measure excludes conventional hydroelectricity.

(Metric 21.b) Metric tons of $CO_2$ reduced by renewable energy resources including wind, photovoltaics/solar thermal electric, biomass, and small hydroelectric generation. This measure provides a maximum amount of avoided carbon dioxide emissions due to grid-connected renewable energy using smart grid features.

(*Metric 21.c) Percent of grid-connected renewable electricity directly and indirectly resultant from smart grid applications.* The metric reduces Metric 21.b to reflect the net benefit of renewable electricity generation that occurs due to the smart grid infrastructure. Metric 21.c removes all renewable electricity except intermittent wind and solar generation and reduces the measure to those emissions occurring as the marginal benefit attributed to use of regulation and spinning reserves.

### A.21.3 Deployment Trends and Projections

Renewable electricity generation climbed from a little over 2 percent of total grid-connected electricity generation in 2005, to over 3.5 percent in 2009 and 2010 (Figure A.60). The increase in renewables generation resulted primarily from an increase in wind generation. Wind generation increased dramatically over the time period from approximately 18 gigawatt-

[442] Roberts D. 2010. "Renewables and the Smart Grid." *Power & Energy*, Issue 7. Accessed June 22, 2010 at http://www.nextgenpe.com/article/Renewables-and-the-Smart-Grid/ (undated webpage).

hours (GWh) in 2005 to more than 70 GWh in 2010.[443] Other-grid-connected renewable electricity production remained relatively constant (Figure A.61).

Primary causes for the increased amount of wind arise from increasing requirements by states for renewable portfolio standards (RPS). The state RPS sets the amount of total generation that must come from renewable resources. Typically, these are set state by state, with some states having strict timelines with required steps, while others have less stringent standards, and yet other states have no RPS requirements. Currently, 30 states and the District of Columbia have RPS requirements.[444] Wind is the least-cost alternative between wind and solar when incentives are included. In addition, where states mandate a set-aside for solar, the amount is significantly smaller than the overall requirement for renewable energy generation. Without significant state and federal incentives for renewables, the current level of renewables generation would be significantly lower. Biomass and geothermal resources are very dependent on economical and reliable resources for electricity generation.

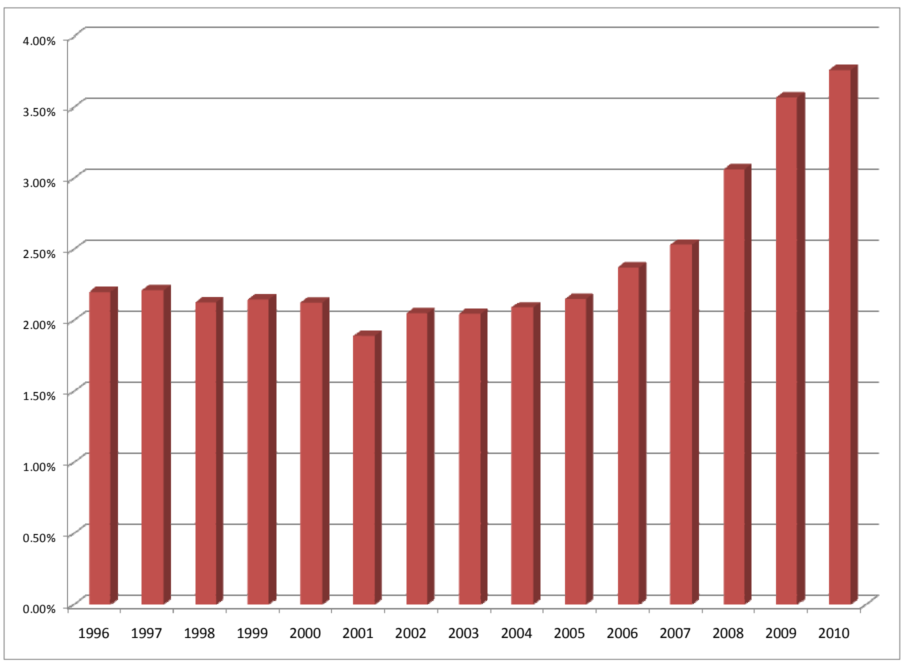


**Figure A.60**. Trends in Renewables as a Percent of Total Net Generation[445,446]

[443] EIA – Energy Information Administration. June 2010c. *Electric Power Monthly*. Energy Information Administration, Washington, D.C. Accessed June 18, 2010 at http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html (undated webpage).

[444] EIA – Energy Information Administration. 2010d. *Annual Energy Outlook 2010*. DOE/EIA-0383(2010), Energy Information Administration, Washington, D.C. Accessed June 23, 2010 at http://www.eia.doe.gov/oiaf/aeo/ (undated webpage).

[445] EIA 2010c.

[446] The percent of net generation for 2010 is based on the first three months of net generation data for 2010.

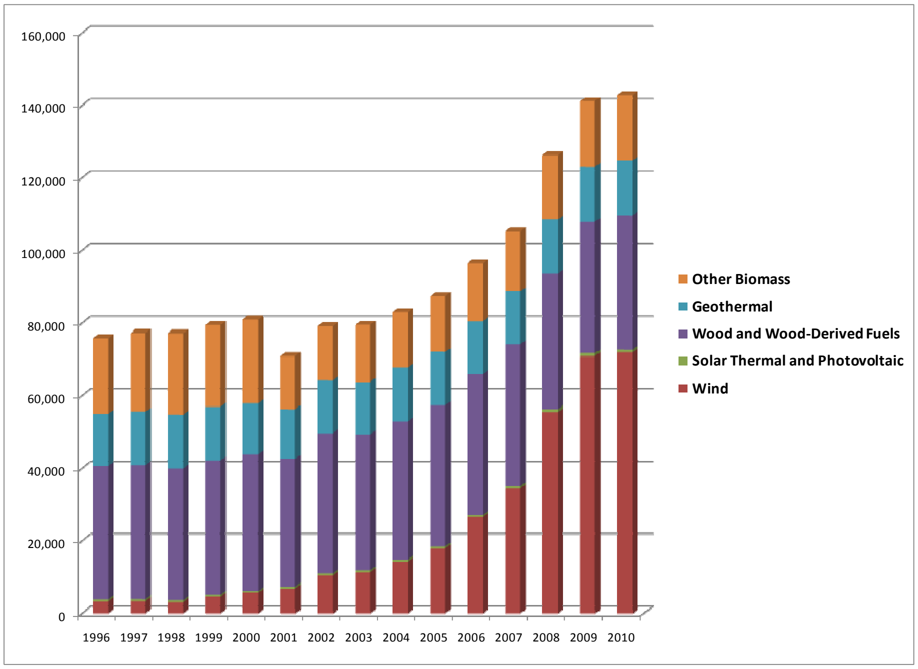


**Figure A.61**. Net Generation by Renewable Energy Resource Type (GWh)[447]

Renewable energy capacity as a percent of total summer peak capacity has grown by almost 50 percent since 2004, increasing from just over 4 percent to almost 6 percent. The percentage is relatively small on a national average basis. Wind and solar net summer capacity as a percent of total summer peak capacity was the measure used to evaluate the U.S. average penetration for intermittent renewables. Currently, nationwide intermittent generation is at about 2.5 percent penetration on a capacity basis (Figure A.62).[448] The wind capacity forecast more than doubles nationwide by 2035, reaching 5.5 percent.[449]

[447] EIA 2010c.
[448] EIA 2010c.
[449] EIA 2010d.

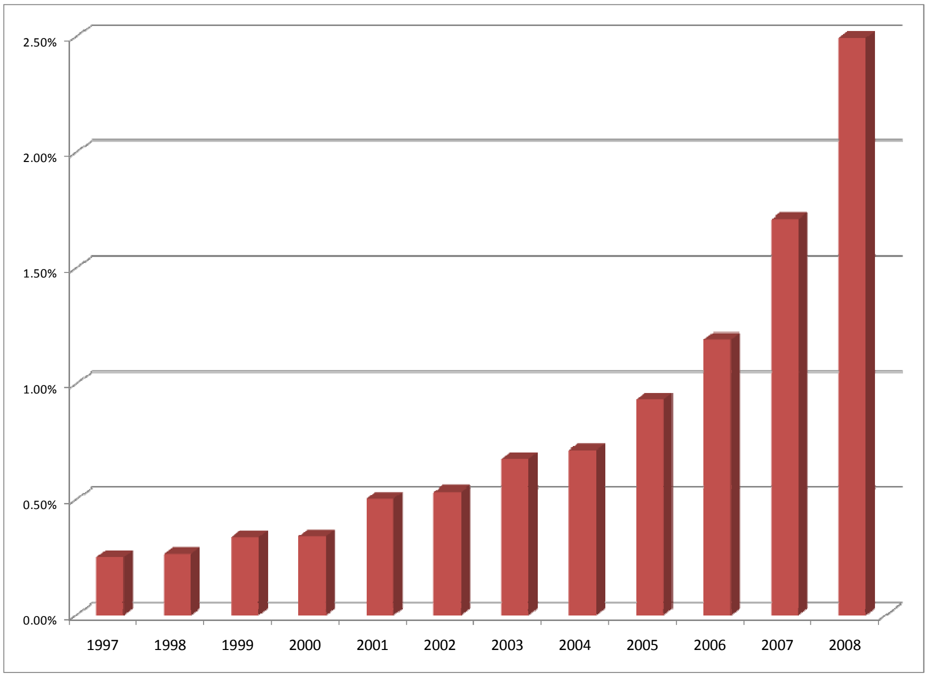


**Figure A.62**. Other Renewable Energy Capacity as Percent of Total Summer Peak Capacity[450]

Renewable resource electricity output is expected to grow significantly between 2008 and 2020 when total renewables generation will triple. Production by renewables is forecast to slow thereafter, only increasing an additional 33 percent between 2020 and 2030. The main contributors to overall growth are biomass and wind, with biomass exceeding wind by 2030. Neither municipal solid waste nor geothermal contribute significantly to other renewable resource electricity generation (see Table A.26). In the base case, renewables account for nearly 45 percent of the increased generation by 2035. The reference case assumes that the production tax credit (PTC) sunsets in 2012 or 2013, depending on the renewable type. If the PTC is assumed to be renewed, alternative cases indicate that renewables could account for 61 to 65 percent of the new generation.[451]

[450] EIA 2010c.
[451] EIA 2010d.

**Table A.26**. Forecast Generation of Non-hydroelectric Renewable Electricity Production 2008 to 2035 (GWh)[452]

| Resource/Year | 2008 | 2020 | 2030 | 2035 |
|---|---|---|---|---|
| MSW | 16.51 | 27.70 | 27.74 | 27.74 |
| Biomass | 38.80 | 144.20 | 268.44 | 290.19 |
| Wind | 52.20 | 198.90 | 206.57 | 217.78 |
| Solar Thermal | 2.10 | 18.53 | 21.43 | 24.81 |
| Geothermal | 14.86 | 23.54 | 25.88 | 28.13 |

Wind-driven avoided emissions have reached almost 140 million metric tons.[453,454] Figure A.63 shows the gross benefit of avoided $CO_2$ emissions from grid-connected renewable electricity generation based on the average amount of emissions for non-renewable energy resources. The last year of data on actual emissions was 2008. We assumed the same level of emissions rate for non-renewable energy resources and applied that rate to 2009 generation of renewable energy resources.

The definition of smart-grid-enabled renewable electricity needs to be developed in order to get a more clear measure of the avoided emissions. The following were not include in the strict interpretation of smart-grid-enabled renewable generation: renewable electricity generated under distributed methods; electricity that is integrated using direct load controls; renewable generation due to the increased amount of forecasting and communicating that is required to integrate intermittent resources; and the amount of electricity that is generated in small independent power plants that must be sold and wheeled on an ever-more-congested transmission system. However, determining the amount of carbon reduction attributable to the smart grid will always be difficult because the smart grid value is fundamentally in reducing costs and eliminating some barriers. All of these attributes are included in smart grid enabling features, but were not included in the strict definition.

[452] EIA – Energy Information Administration. 2010e. "Figure 65: Nonhydroelectric Renewable Electricity Generation by Energy Source." *Annual Energy Outlook 2010*. DOE/EIA-0383(2010), Energy Information Administration, Washington, D.C. Accessed June 23, 2010 at http://www.eia.doe.gov/oiaf/aeo/graphic_data.html (last updated May 11, 2010).

[453] EIA – Energy Information Administration. 2009a. *Emissions of Greenhouse Gases Report*. DOE/EIA-0573, Energy Information Administration, Washington, D.C. Accessed June 18, 2010 at http://www.eia.doe.gov/oiaf/1605/ggrpt/carbon.html (last updated (December 3, 2009).

[454] EIA 2010c.

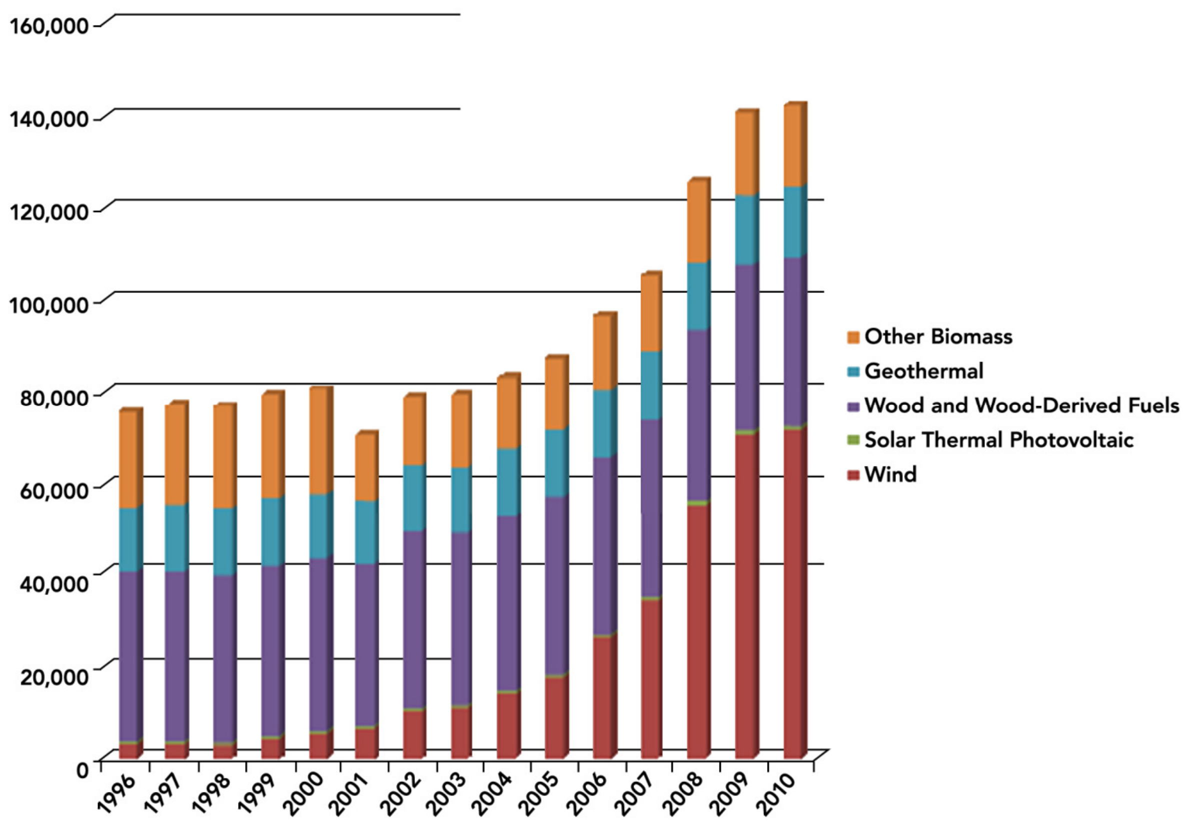


**Figure A.63**. Avoided $CO_2$ Emission by Renewable Energy Electricity Generation (Million Metric Tons $CO_2$)[455]

#### A.21.3.1 Associated Stakeholders

Stakeholders include distribution and transmission service providers, balancing authorities, wholesale-electricity traders/brokers/markets, electric-service retailers, reliability coordinators, product and service suppliers, energy policymakers and regulators, standards organizations, the financial community, and end users (consumers).

- Transmission service providers will need to add significant amounts of transmission lines to effectively transport wind energy from distant production centers to urban population centers.
- Distribution service providers will need to provide net metering opportunities and establish connection standards, advanced voltage control, and short-circuit protection schemes at high penetration of renewables.
- Balancing authorities will need the latest in smart grid options to provide them with the ability to balance loads when large amounts of intermittent renewable electricity are part of

[455] EIA 2009a.

the mix, including interruptible load mechanisms and direct load control. They will need to coordinate transmission of the renewable energy resource between system operators.

- Electric-service retailers will need to balance their distribution loads based on potential distributed generation units within their local grid. In states with renewable portfolio standards, utilities will need to acquire the requisite amounts of renewable energy to meet the requirements.
- Reliability coordinators will need to implement processes and procedures that provide stability and power quality to the grid, given the amount of instability large quantities of intermittent renewable energy will cause.
- Policymakers and regulators will need to develop the laws and regulations governing interstate transmission. Cooperation between state and federal regulators and investment from the financial community will be required to build the extra-high voltage (EHV) transmission lines required to deliver electricity from distant production areas.
- Standards organizations will need to write the standards that allow the interoperability between different equipment types and systems required to integrate the intermittent resources.
- Independent power producers require markets to deliver their renewable electricity. Without adequate prices and demand for intermittent electricity, investments will not be undertaken.
- Product and service providers will need to continuously improve renewable energy technologies to make them competitive as the government reduces subsidies. In addition, they will need to develop technologies required to make the load more flexible, including fuel synthesis technologies, storage technologies, and generation technologies that can quickly ramp to meet changes in intermittent capacity. Weather forecast service providers will be pressed to find more accurate methods of forecasting weather to improve planning for spinning reserves and regulation.
- The financial community will provide a significant amount of the capital that will be required to implement a smart grid with a significant amount of intermittent renewable energy. Wind and solar power equipment will need to be purchased, and if wind and solar are developed in regions far from demand centers, significant capital will be needed to purchase the transmission lines and infrastructure to integrate the electricity produced.
- End users will benefit from a decreased carbon footprint in the electricity sector, but will pay higher prices for wind- and solar-produced electricity. However, as the renewable footprint grows, more price stability will occur as fossil-fuel price volatility will have less impact.

### A.21.3.2 Regional Influences

The most economic renewable energy resources, such as wind and solar, are located in specific regions. The highest solar potential exists in the desert southwest, while the best wind exists in the West and Midwest. Areas along the Atlantic Coast and Southeast have little wind inland, and the level of humidity degrades the solar resource. Figure A.64 indicates the type of renewable energy generation as a percent of total renewable generation.

The Pacific West region has the greatest amount of renewable electricity generation as a percent of total generation, followed by the South Atlantic and Southwest Central regions, and the Pacific West has the largest percentage of solar and geothermal, and the second highest wind. The Southwest Central (including Texas) has the largest percentage of wind. The South Atlantic region leads in the biomass/biogenic types of renewable resources. Biomass is expected to exceed wind as the major source of renewable energy production by 2030.[456]

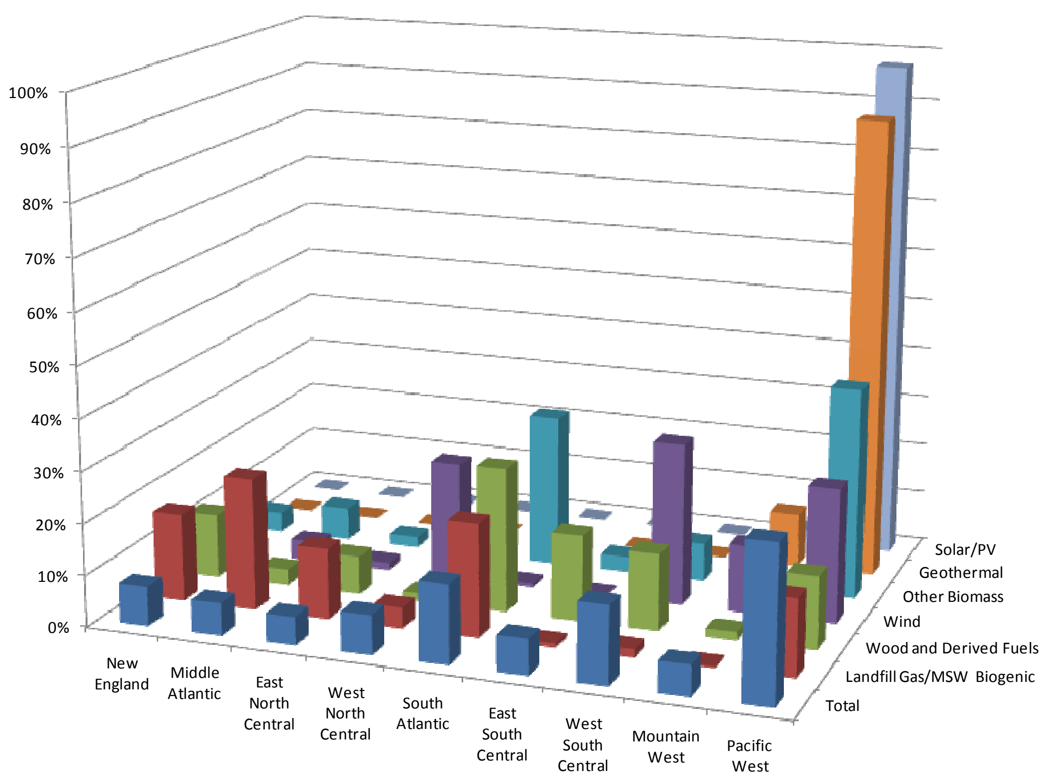


**Figure A.64**. Regional Renewable Generation as Percent of Total Renewable Generation, Percent of Renewable Generation Type by region, 2006[457]

[456] EIA 2010e.

[457] EIA – Energy Information Administration. April 2009b. "Renewable Energy Trends in Consumption and Electricity, 2007." *Renewable Energy Annual 2007*. Energy Information Administration, Washington, D.C. Accessed June 18, 2010 at http://www.eia.gov/FTPROOT/renewables/060307.pdf (last updated May 21, 2009).

## A.21.4 Challenges to Deployment

There are a number of technical and business/financial barriers to implementing smart grid technologies that incorporate renewable electricity generation. These include maintaining grid stability, cost-effective storage technologies, and a relatively high direct cost per installed kW of capacity for the intermittent sources. These barriers could stall investment in these technologies.

### A.21.4.1 Technical Challenges

Technical barriers include:

- Perhaps the largest technical hurdle for intermittent renewable energy resources to overcome is the impact to grid stability and the fact that wind and solar resources are not dispatchable (or drawn upon when demand increases above baseload). Even scale and dispersion will not overcome the variability in production. As such, storage technologies currently under development will need to become cost-effective and commercialized.[458] The California ISO noted in their draft report on wind integration that energy ramps as high as 3,000 MW per hour or larger were possible during summer peak.[459]
- A Northwest Power and Conservation Council study indicated that five classes of technologies are needed to improve integration of intermittent wind production: storage, fuel synthesis, generation, demand response, and operational techniques. Noted among the approaches as providing flexibility, and in some level of development, were capacitors/ultra capacitors; flow batteries/flow-redox batteries such as vanadium, zinc bromine, cerium zinc, and polysulfide bromine; MW sized batteries; flywheels; hydrogen storage; fuel cells; call rights (the ability to reduce or shut off power demanded) on plug-in vehicles; and extending wind prediction time. Most of these technologies/techniques that are not at the mature stage were listed as having high capital costs.[460] The emphasis was on providing flexibility to accommodate and balance loads associated with integrating 6,000 MW of wind-generated electricity.
- Wind faces some environmental challenges, in that neighbors complain about noise, lighting effects, and visual pollution.

[458] Kreutzer 2010.

[459] CAISO – California Independent System Operator. 2007. *California ISO Integration of Renewable Resources Report (Draft)*. California Independent System Operator, Folsom, California. Accessed June 23, 2010 at http://www.caiso.com/1c60/1c609a081e8a0.pdf (undated webpage).

[460] NWPCC – Northwest Power and Conservation Council. March 2007. *The Northwest Wind Integration Plan*. WIF document 2007-01, Northwest Power and Conservation Council, Portland, Oregon. Accessed June 24, 2010 at http://www.nwcouncil.org/energy/Wind/library/2007-1.htm (undated webpage).

#### A.21.4.2 Business and Financial Challenges

Business and financial barriers include:

- Most renewable energy resources are considerably more expensive than coal-fired or natural-gas fired electricity generation facilities. Levelized costs for wind are approximately 50 percent greater than conventional coal, while PV is approximately 400 percent greater than coal.[461] Renewable portfolio standards and the associated renewable energy credits help offset the higher costs. Once current renewable portfolio goals (requirements) have been met, the investment in high-cost renewables is harder to make because of the lack of demand for renewable energy credits.
- Potential wind resources will require significantly more transmission lines to bring electricity from good resource areas to the grid. Wind typically is found in less populated areas where there are fewer transmission lines. AEP estimates that $60 billion will need to be invested in 19,000 miles of EHV transmission lines to deliver electricity from distant generation regions to demand centers.[462]
- Most of the technologies/techniques required to make the grid system more flexible are characterized as immature technologies and are listed as having high capital costs.[463]

### A.21.5 Metric Recommendations

A clearer definition of how the smart grid enables renewables integration is needed. Currently, various studies apply different values to the amount of renewable energy transmission that is supported by smart grid functions. Some argue that all renewables generation is based on some smart grid application to integrate the electricity. Without synchrophasors and direct load controls, integration of intermittent generation would cause system failure more often than it does now. On the other hand, others argue these technologies are not new, and therefore are not a smart grid application.

[461] EIA – Energy Information Administration. January 2010f. "2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010." *Annual Energy Outlook 2010*. Energy Information Administration, Washington, D.C. Accessed June 18, 2010 at http://www.eia.doe.gov/oiaf/aeo/electricity_generation.html (last updated January 12, 2010).

[462] Smith DC. January 1, 2009. "Integrating Renewables into US Utility Portfolios." *Renewable Energy Focus.com*. Accessed June 22, 2010 at http://www.renewableenergyfocus.com/view/1398/utilities-in-the-usa-the-challenge-of-integration-/ (last updated January 1, 2009).

[463] NWPCC 2007.