U.S. Department of

ENERGY

2010 Smart Grid System Report

Report to Congress

February 2012

United States Department of Energy

Washington, DC 20585

Message from the Assistant Secretary

February 2012

The Department of Energy is responding to Section 1302 of Title XIII of the Energy Independence and Security Act (EISA), which directs the Secretary of Energy to report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. This document is the second installment of this report to Congress, which is to be updated biennially.

The 2010 Smart Grid System Report (SGSR) to Congress explores the current status of smart grid development, its future prospects, and the technical and financial obstacles to progress. It also outlines the scope of a smart grid, assesses the stakeholder landscape and provides several recommendations for future reports.

A smart grid uses digital technology to improve the reliability, security, and efficiency of the electricity system: from large generation through the delivery systems to electricity consumers and a growing number of distributed generation and storage resources. The information networks that are transforming our economy in other areas are also being applied to applications for dynamic optimization of electricity system operations, maintenance, and planning. Resources and services that had been separately managed are now being integrated and re-bundled as we address traditional problems in new ways, adapt the system to tackle new challenges, and discover new benefits that have transformational potential.

The report concludes that near-term progress in smart grid deployments has been significant due primarily to the investments made under the American Recovery and Reinvestment Act (ARRA) of 2009. The far-reaching impacts of ARRA include: funding a $2.4 billion program designed to establish 30 manufacturing facilities for electric vehicle batteries and components, funding the deployment of 877 phasor measurement units, $812.6 million in federal grant awards for advanced metering infrastructure deployments, and the provision of $7.2 billion to expand broadband access and adoption. The report also highlights other significant developments occurring since the last SGSR that have resulted in progress toward achieving a smart grid. Pursuant to statutory requirements, this report is being provided to the following Members of Congress:

- **The Honorable Joseph Biden**
  President of the Senate
- **The Honorable John Boehner**
  Speaker of the House of Representatives
- **The Honorable Daniel K. Inouye**
  Chairman, Senate Committee on Appropriations
- **The Honorable Thad Cochran**
  Ranking Member, Senate Committee on Appropriations
- **The Honorable Hal Rogers**
  Chairman, House Committee on Appropriations
- **The Honorable Norm Dicks**
  Ranking Member, House Committee on Appropriations
- **The Honorable Fred Upton**
  Chairman, House Committee on Energy and Commerce
- **The Honorable Henry A. Waxman**
  Ranking Member, House Committee on Energy and Commerce
- **The Honorable Edward Whitfield**
  Chairman, Subcommittee on Energy and Power
  House Committee on Energy and Commerce
- **The Honorable Bobby Rush**
  Ranking Member, Subcommittee on Energy and Power
  House Committee on Energy and Commerce
- **The Honorable Jeff Bingaman**
  Chairman, Senate Committee on Energy and Natural Resources
- **The Honorable Lisa Murkowski**
  Ranking Member, Senate Committee on Energy and Natural Resources

If you have any questions or need additional information, please contact me or Mr. Robert Tuttle, Office of Congressional and Intergovernmental Affairs, at (202) 586-5450.

Sincerely,

Patricia a Hoffman

Patricia A. Hoffman, Assistant Secretary
Office of Electricity Delivery and Energy Reliability

Executive Summary

Section 1302 of Title XIII of the Energy Independence and Security Act (EISA) of 2007 directs the Secretary of Energy to "…report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment." This document is the second installment of this biennial report.

A smart grid uses digital technology to improve the reliability, security, and efficiency of the electricity system, from large generation through the delivery systems to electricity consumers. Smart grid deployment covers a broad array of electricity system capabilities and services enabled through pervasive communication and information technology, with the objective of improving reliability, operating efficiency, resiliency to threats, and our impact on the environment.

Near-term progress in smart grid deployments has been significant due primarily to the investments made under the American Recovery and Reinvestment Act (ARRA) of 2009, including:

- providing $4.5 billion in awards for all programs described under Title XIII (111 USC 405)
- funding a $2.4 billion program designed to establish 30 manufacturing facilities for electric vehicle batteries and components
- funding the deployment of 877 phasor measurement units
- providing $812.6 million in federal grant awards for advanced metering infrastructure deployments
- providing $7.2 billion to expand broadband access and adoption
Recent progress toward achieving a smart grid also includes the following:
- There are now 29 states that have renewable portfolio standards.
- Distributed resource interconnection policies have been either implemented or expanded in 14 states since 2008, thus promoting the advancement of distributed generation technologies.
- Incentives to purchase and own electric vehicles and plug-in hybrid electric vehicles are either planned or provided in 21 states.
- The National Institute of Standards and Technology published the first release of the framework for smart grid interoperability standards and guidelines for smart grid cyber security.

With the aforementioned progress noted, significant challenges to realizing smart grid capabilities persist. Foremost among these are the challenges tied to the value proposition and the capital required to purchase the new technologies envisioned for communicating information between end-users, energy providers, and distribution and transmission providers. These and other challenges are explored in this report, as are recommendations for enhancing future smart grid system reports.

Acronyms and Abbreviations

AC	Auditably Compliant, alternating current
ACES	American Clean Energy and Security Act
AEO	Annual Energy Outlook
AEP	American Electric Power
AMI	advanced metering infrastructure
AMR	automated meter reading
ARPA-E	Advanced Research Projects Agency-Energy
ARRA	American Recovery and Reinvestment Act
ATVM	Advanced Technology Vehicle Manufacturing
BA	balancing authority
BAT	best available technology
BAU	business-as-usual
BCCS	Base Case Coordination System
BES	bulk electricity system
BEV	battery electric vehicle
BGE	Baltimore Gas and Electric
BPA	Bonneville Power Administration
CAES	compressed-air energy storage system
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAPEX	capital expenditures
CBL	customer baseline load
CCET	Center for the Commercialization of Electric Technologies
CCS	carbon capture and sequestration
CEC	California Energy Commission
CERTS	Consortium for Electric Reliability Technology Solutions
CES	community energy storage
CHP	combined heat and power
CIM	common information model
CIP	critical infrastructure protection
CL&P	Connecticut Light and Power

CMM	Capability Maturity Model
CMMI	Capability Maturity Model for Software Integration
CO_2	carbon dioxide
CPP	critical-peak pricing
DER	distributed energy resources
DG	distributed generation
DHS	Department of Homeland Security
DLC	direct load control
DLR	dynamic line ratings
DMS	distribution management system
DoD	United States Department of Defense
DOE	United States Department of Energy
DOE-OE	United States Department of Energy Office of Electricity Delivery and Energy Reliability
DSIRE	Database of State Incentives for Renewable Energy
DSM	demand-side management
DTCR	Dynamic Thermal Circuit Rating
DTE	DTE Energy Company
EEI	Edison Electric Institute
EHV	extra-high voltage
EIA	Energy Information Administration
EIPP	Eastern Interconnection Phasor Pilot
EISA	Energy Independence and Security Act of 2007
EMS	energy management system
EPA	United States Environmental Protection Agency
EPACT 2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FY	fiscal year
GE	General Electric Company

GWAC	DOE's GridWise® Architecture Council
GWh	gigawatt-hours
HAN	home area network
HECO	Hawaiian Electric Company, Inc.
HVAC	Heating, Ventilation, & Air Conditioning
IED	intelligent electronic device
IEEE	Institute of Electrical and Electronics Engineers
INL	Idaho National Laboratory
IOU	investor-owned utility
IREC	Interstate Renewable Energy Council
ISO	independent system operator
ISO-NE	Independent System Operator – New England
IT	information technology
KCP&L	Kansas City Power and Light
kW	kilowatt
kWh	kilowatt-hour
LBNL	Lawrence Berkley National Laboratory
LG&E	Louisville Gas and Electric
LRAM	lost revenue adjustment mechanism
LUF	line under-frequency
MAIFI	Momentary Average Interruption Frequency Index
MAPP	Mid-Atlantic Power Pathway
MRO	Midwest Reliability Organization
MSRP	manufacturer's suggested retail price
MW	megawatts
MWh	megawatt-hours
NARUC	National Association of Regulatory Utility Commissioners
NASPI	North American SynchroPhasor Initiative
NEHTA	National E-Health Transition Authority (Australia)
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Corporation
NESC	National Electric Safety Code
NETL	National Energy Technology Laboratory
NIST	National Institute of Standards and Technology

NNEC	Network for New Energy Choices
NPCC	Northeast Power Coordinating Council
NRDC	Natural Resources Defense Council
NSF	National Science Foundation
NTIA	National Telecommunications and Information Administration
NYISO	New York Independent System Operator
OEM	original equipment manufacturer
ORNL	Oak Ridge National Laboratory
OWL	Web Ontology Language
PDC	phasor data concentrators
PG&E	Pacific Gas and Electric Company
PHEV	plug-in hybrid electric vehicles
PJM	PJM Interconnection, Inc.
PM	particulate matter
PMU	phasor measurement units
PNNL	Pacific Northwest National Laboratory
PQ	power quality
PSC	public service commission
PTC	production tax credit
PUC	public utility commission
PUCT	Public Utility Commission of Texas
PV	photovoltaic systems
R&D	research and development
RC	reliability coordinator
RDC	Resource Dynamics Corporation
RDF	Resource Description Framework
RES	renewable energy source
RFC	Reliability First Corporation
RMS	root-mean square
ROI	return on investment
RPS	renewable portfolio standards
RTEP	regional transmission expansion plan
RTO	regional transmission operator
RTP	real-time pricing

RUS	Rural Utility Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAR	Standard Authorization Request
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SEI	Software Engineering Institute
SERC	Southeast Reliability Corporation
SGIG	Smart Grid Investment Grant
SGIMM	Smart Grid Interoperability Maturity Model
SGIP	Smart Grid Investment Program, Self-Generation Incentive Program
SGSR	Smart Grid System Report
SPP	Southwest Power Pool
SUV	sport utility vehicle
T&D	transmission and distribution
TB	terabytes
TLR	transmission loading relief
TOP	transmission operators
TOU	time-of-use pricing
TRANSCO	transmission-only companies
TRE	Texas Regional Entity
TVA	Tennessee Valley Authority
TWh	terawatt hours, trillion watt hours
UMTRI	University of Michigan Transportation Research Institute
U.S.	United States of America
USDA	United States Department of Agriculture
V2G	vehicle-to-grid
VAR	volt-amps reactive
VMT	vehicle miles traveled
WAMS	wide area measurement system
WECC	Western Electricity Coordinating Council
WISP	Western Interconnection Synchrophasor Program

Table of Contents

Figures

Tables

1.0 Introduction

Section 1302 of Title XIII of the Energy Independence and Security Act of 2007 (EISA) directs the Secretary of Energy to, "…report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment" (110 USC 1302). The first Smart Grid System Report (SGSR) was published in July 2009. This document represents the second installment of this report to Congress, which is to be updated biennially.

1.1 Objectives

The objective of Title XIII is to support the advancement of the Nation's electricity system, to maintain a reliable and secure infrastructure that can meet future load growth and achieve the characteristics of a smart grid. The SGSR is to provide the current status of smart grid development, the prospects for its future, and the obstacles to progress. In addition to providing the state of smart grid deployments, the legislation includes the following requirements and recommendations:

- Report the prospects of smart grid development, including costs and obstacles.
- Identify regulatory or government barriers.
- May provide recommendations for state and federal policies or actions.
- Take a regional perspective.

The first SGSR set the framework for future reports, as originally defined in Section 1302 of Title XIII of EISA. This report, while retaining the original framework, goes into greater detail by expanding the number of metrics explored in the report and using the baseline established in the 2009 SGSR to update smart grid related progress. Figure 1.1 provides a pictorial view of the many elements of the electricity system touched by smart grid concerns. The 21 metrics evaluated in this report touch every element identified in the figure, from the accommodation of all generation and energy options to the integration of end-user equipment, including electric vehicles (EVs), smart appliances, and distributed generators.

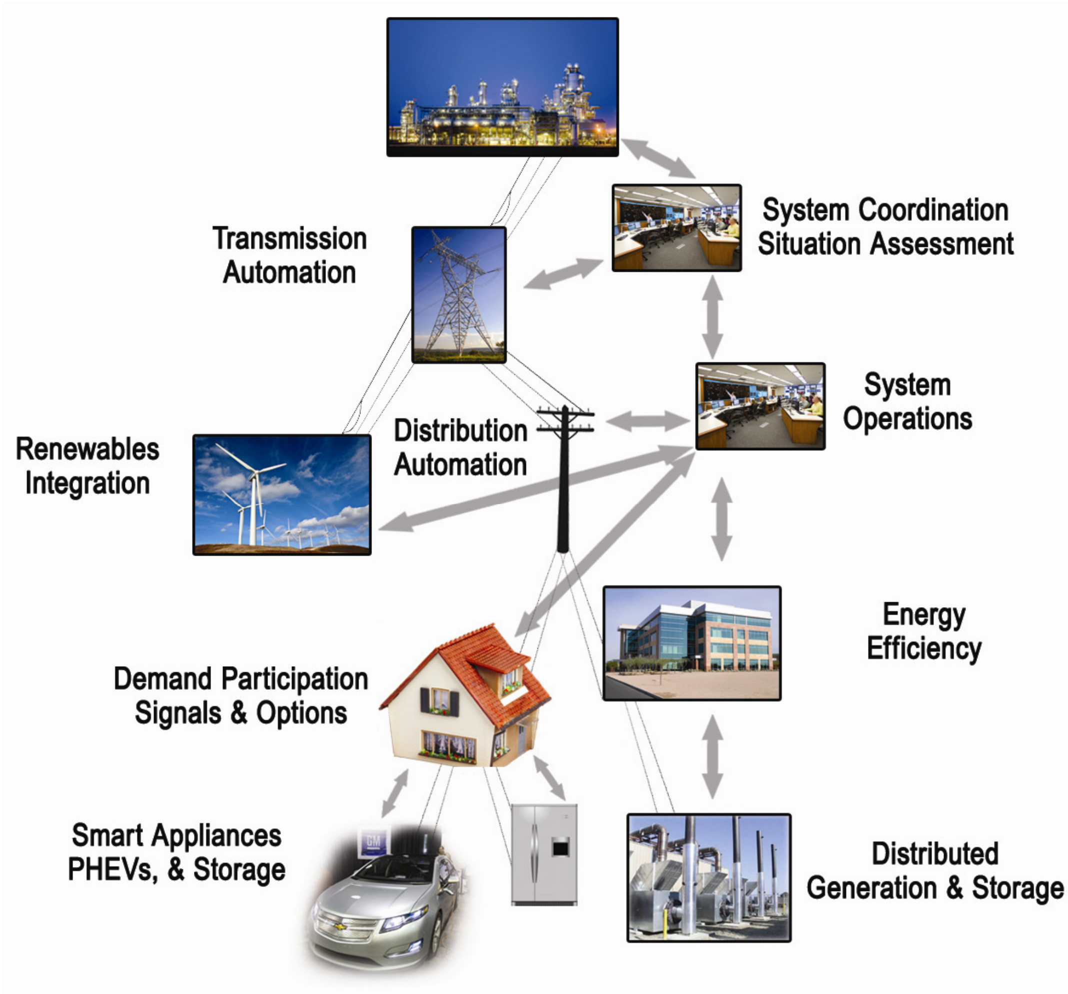


Figure 1.1. Scope of Smart Grid Concerns

1.2 Scope of a Smart Grid

A smart grid uses digital technology to improve the reliability, security, and efficiency of the electricity system. Due to the vast number of stakeholders and their various perspectives, there has been debate on a definition of a smart grid that addresses the special emphasis desired by each participant. This report retains the definition established in the 2009 SGSR, as outlined in the remainder of this section.

The following areas arguably represent a reasonable partitioning of the electricity system that covers the scope of smart grid concerns. To describe the progress being made in moving toward a smart grid, one must also consider the interfaces between elements within each area and the systemic issues that transcend areas. The areas of the electricity system that cover the scope of a smart grid include the following:

- Area, regional and national coordination regimes: A series of interrelated, hierarchical coordination functions exists for the economic and reliable operation of the electricity system. These include balancing areas (BAs), independent system operators (ISOs), regional transmission operators (RTOs), electricity market operations, and government emergency-operation centers. Smart grid elements in this area include collecting measurements from across the system to determine system state and health, and coordinating actions to enhance economic efficiency, reliability, environmental compliance, or response to disturbances.
- Distributed-energy resource technology: Arguably, the largest "new frontier" for smart grid advancements, this area includes the integration of distributed generation (DG), storage, and demand-side resources for participation in electricity system operation. Smart appliances and EVs will become important components of this area, as are renewable-generation components such as those derived from solar and local wind sources. Aggregation mechanisms of distributed energy resources (DER) are also considered.
- Delivery transmission and distribution (T&D) infrastructure: this represents the delivery part of the electricity system. Smart grid items at the transmission level include substation automation; dynamic limits; relay coordination; and the associated sensing, communication, and coordinated action. Distribution-level items include distribution automation (such as feeder-load balancing, capacitor switching, and restoration) and advanced metering (such as meter reading, remote-service enabling and disabling, and demand-response gateways).
- Central generation: generation plants already contain sophisticated plant automation systems because the production cost savings provide clear signals for investment. While technological progress in automation continues, the change is expected to be incremental rather than transformational, and therefore, this area is not emphasized as part of this report.
- Information networks and finance: information technology and pervasive communications are cornerstones of a smart grid. Though the information network requirements (capabilities and performance) will be different in different areas, their attributes tend to transcend application areas. Examples include interoperability and the ease of integration of automation components, as well as cyber security concerns. Information-technology-related standards, methodologies, and tools also fall into this area. In addition, the economic and investment environment for procuring smart-grid-related technology is an important part of the discussion concerning implementation progress.

Section 1301 of EISA identifies characteristics of a smart grid. The National Energy Technology Laboratory (NETL) Modern Grid Initiative provides a list of smart grid attributes in What is the Smart Grid? (Miller 2008). These characteristics were used to help organize a workshop sponsored by the U.S. Department of Energy (DOE) on "Implementing the Smart

Grid" (OE 2008). The results of that workshop were used to organize the reporting of smart grid progress around six characteristics:

- Enabling Informed Participation by Customers
- Accommodating All Generation & Storage Options
- Enabling New Products, Services, & Markets
- Providing Power Quality for the Range of Needs
- Optimizing Asset Utilization & Operating Efficiency
- Operating Resiliently: Disturbances, Attacks, & Natural Disasters.

These characteristics were retained from the 2009 SGSR.

1.3 Stakeholder Landscape

Some aspect of the electricity system touches every person in the Nation. The smart grid stakeholder landscape is complex, as demonstrated in Figure 1.2. The lines of distinction are not always crisp, as corporations and other organizations can take on the characteristics and responsibilities of multiple functions.

Stakeholders include the following:

- end users (consumers): industrial, commercial, residential
- electricity service retailers: regulated and unregulated electricity and other service providers (including service and resource aggregators)
- distribution-service providers: generally electricity distribution utilities (public and private)
- transmission providers: generally electricity transmission owners and operators (public and private)
- balancing authorities
- generation and demand wholesale-electricity traders/brokers
- wholesale market operators
- reliability coordinators including the North American Electric Reliability Corporation (NERC)
- products and services suppliers including information technology (IT) and communications
- local, state, and federal energy policymakers (regulators, legislators, executives, and related offices)
- policy advocates (consumer groups, trade organizations, environmental advocates)

- standards organizations
- research organizations
- the financial community.

The major stakeholder groups are referenced throughout the report as appropriate to the topic in question.

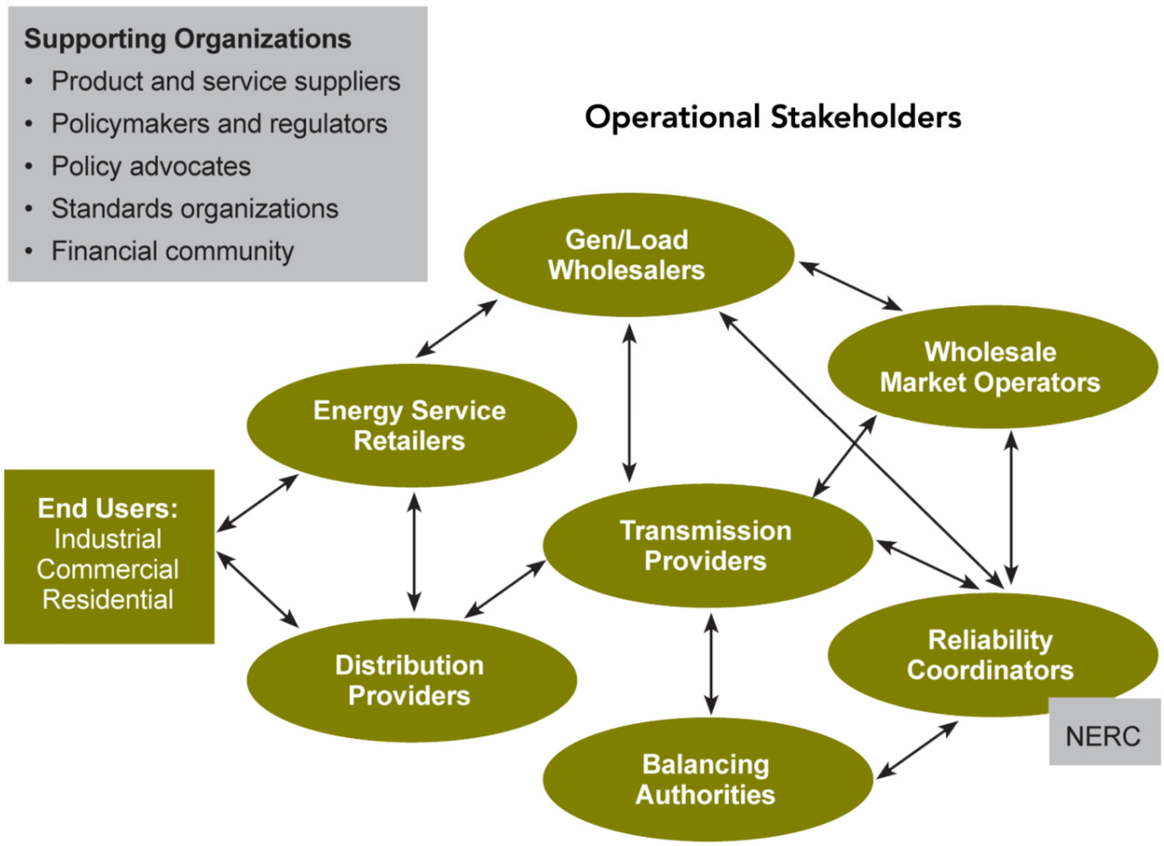


Figure 1.2. Stakeholder Landscape

1.4 Regional Influences

Different areas of the country have distinctions with regard to their generation resources, their business economy, climate, topography, environmental concerns, and public policy. These distinctions influence the picture for smart grid deployment in each region, provide different incentives, and pose different obstacles for development. The major regions of the country can be divided into the 10 NERC reliability regions (see Figure 1.3) (EPA 2008a). The Environmental Protection Agency (EPA) further subdivides these into 26 sub-regions (see EPA map, Figure 1.4), and each of these regions has its distinctive state and local governments.

Regional factors are woven into various aspects of the report, including the smart grid deployment metrics, deployment attributes, trends, and obstacles. Discussion will target the states and major NERC reliability regions.

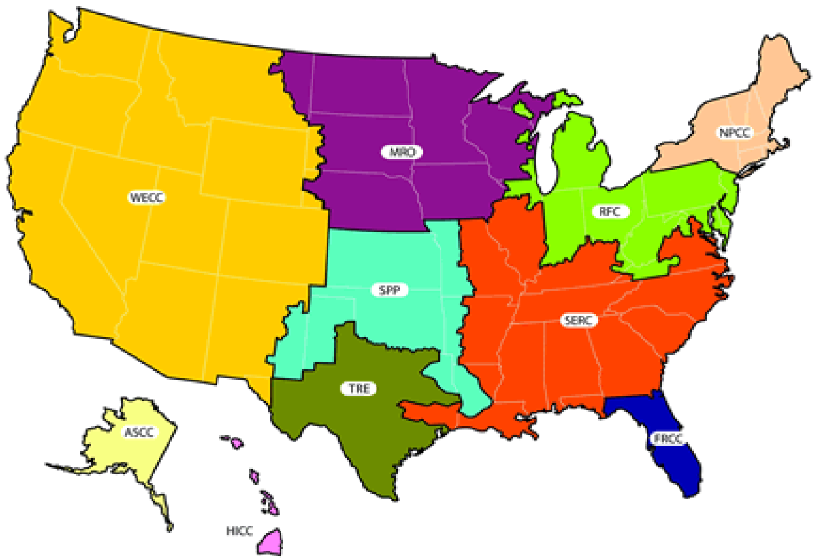


Figure 1.3. NERC Region Representation Map

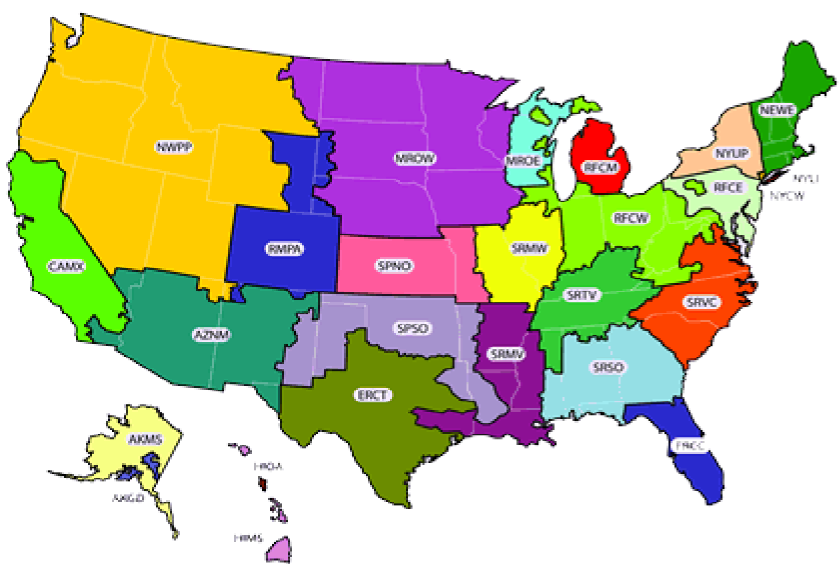


Figure 1.4. EPA eGRID Subregion Representational Map

1.5 What's New in this Report

In May of 2010, the Pacific Northwest National Laboratory (PNNL) solicited stakeholder feedback on the SGSR by hosting a series of webinars. At these webinars, which are discussed in greater detail in Section 2.1 of this report, stakeholders provided input regarding the metrics used in the SGSR. Based on the input received from those webinars, a small number of changes were made to the 2010 SGSR:

- An additional metric [Metric 21–Grid-Connected Renewable Resources] has been added that measures the generation levels associated with grid-connected renewable resources and the displaced carbon dioxide (CO2) emissions attributed to their presence.
- Several metrics [Metrics 6–Load Served by Microgrids, 9–Grid-Responsive Non-Generating Demand-Side Equipment, 16–Dynamic Line Ratings, , and 19–Open Architecture/Standards] were deemed to be both nascent and not readily measurable given current data constraints. In each case, the decision was made to keep the metric, monitor progress, and re-evaluate it prior to including it in future SGSRs. Each metric addressed an area that was viewed as having significant but as yet unrealized potential.

In addition, DOE's Energy Advisory Committee and their Smart Grid Subcommittee were consulted along with the inter-agency Smart Grid Task Force that includes representatives from the National Institute of Standards and Technology (NIST), the Federal Energy Regulatory Commission (FERC), the Department of Homeland Security (DHS), and EPA, among others.

Unlike the first SGSR, this report does include impacts related to the American Recovery and Reinvestment Act of 2009 (ARRA). EISA provided incentives for electricity companies to undertake smart grid investments. Section 1306 authorized the Secretary of the U.S. DOE to establish the Smart Grid Investment Matching Grant Program (SGIG), which was designed to provide reimbursement for up to 20 percent of an electricity service provider's investment in smart grid technologies. In 2009, ARRA altered sections 1306 and 1307 of Title XIII, providing 100 percent matching grants and designating $4.5 billion in awards for all programs described under Title XIII (111 USC 405). To date, the SGIG program has awarded grants to 99 recipients, including private companies, service providers, manufacturers, and cities, with total public-private investment amounting to over $8 billion (DOE 2009a). The impacts of ARRA on the metrics measured in the SGSR are far-reaching and include the following:

- ARRA funded the deployment of 877 phasor measurement units (PMUs), expanding the prior nationwide network of 200 by more than 400 percent [Metric 2–Real-time System Operations Data Sharing] (Overholt 2010).
- ARRA funded the Center for the Commercialization of Electric Technologies (CCET) Smart Grid Demonstration Project, a demonstration-scale microgrid project in Texas [Metric 6–Load Served by Microgrids].

- ARRA includes a $2.4 billion program designed to establish 30 manufacturing facilities for electric vehicle batteries and components [Metric 8–Electric Vehicles and Plug-in Hybrid Electric Vehicles]. This funding is in addition to the aforementioned $4.5 billion in awards made under ARRA.
- Federal grant awards for advanced metering infrastructure (AMI) deployments under ARRA total $812.6 million to date, with total project values reaching over $2 billion [Metric 12–Advanced Meters] (DOE 2010a).
- ARRA included several provisions that will strengthen the nation's broadband network. ARRA provided $7.2 billion in funding to support grant and loan programs administered by the National Telecommunications and Information Administration (NTIA) and the U.S. Department of Agriculture's (USDA's) Rural Utilities Service (RUS) program, that are designed to expand broadband access and adoption. ARRA also directs the Federal Communications Commission (FCC) to develop and submit to Congress a National Broadband Plan designed to measure progress toward the goal of providing access to broadband capability across the U.S. Expanded access to broadband networks supports several metrics [Metric 1–Dynamic Pricing, Metric 2–Real-time System Operations Data Sharing, Metric 12–Advanced Meters] by enhancing the speed at which information can be uploaded and shared between systems.

Other significant developments affecting the deployment trends reported in the 2010 SGSR include:

- There are 29 states that now have renewable portfolio standards, which include specific percentage goals to lower fossil fuel consumption by incorporating energy efficiency goals and renewable energy generation. These standards have promoted smart grid deployment by expanding or creating new policies for distributed resource interconnection, net metering, energy efficiency programs, and regulatory recovery for smart grid investments.
- NIST released the first phase of a three-phase plan that aims to align smart grid standards. The document, NIST Framework and Roadmap for Smart Grid Interoperability Standards (NIST 2010), initially identified sixteen priority plan areas for smart grid standardization including an initial plan for cyber security.
- NIST has identified the following five foundational families of standards, which are fundamental to smart grid interoperability:
  - International Electrotechnical Commission (IEC) 61970 and IEC 61968: Provides a common information model (CIM) necessary for exchanges of data between devices and networks, primarily in the transmission (IEC 61970) and distribution (IEC 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.
- ARRA projects and data being collected for reporting and analysis will aid future SGSRs.
- The Energy Information Administration (EIA) was funded by ARRA to expand data collection for the smart grid. DOE has been coordinating with the EIA to make sure that the expanded information assists future SGSRs.
- Distributed resource interconnection policies have been either implemented or expanded in 14 states since 2008. As of June 2010, 39 states, Washington, D.C., and Puerto Rico have adopted variations of an interconnection policy. The USDA's RUS Loan Program requires all existing borrowers to have a current and publicly available policy regarding the interconnection of distributed resources. RUS borrowers (this does not include grant recipients) serve customers in 44 states.
- Incentives for purchasing and owning EVs and plug-in hybrid electric vehicles (PHEVs) are either planned or provided in 21 states.[1] 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.

1.6 About This Document

The SGSR is organized into a main body and two supporting appendices. The main body discusses the metrics chosen to provide insight into the progress of smart grid deployment nationally. The measurements resulting from research into the metrics are used to convey the state of smart grid progress according to six characteristics derived from the NETL Modern Grid Initiative's work in this area and discussions at the DOE Smart Grid Implementation Workshop. The main body of the report also summarizes the barriers to smart grid deployment, including technical, business, and financial challenges, and concludes with a set of recommendations for improving future SGSRs. Appendix A presents a discussion of each of the metrics chosen to help measure the progress of smart grid deployment. Appendix B summarizes the results of interviews with electricity service providers chosen to represent a cross section of the nation in terms of size, location, and type of organization (e.g., public or private company, rural electric cooperative).

[1] The PHEV is a hybrid electric vehicle with batteries that can be recharged when plugged into an electric wall outlet and an internal combustion engine that can be activated when batteries require recharging.

Finally, DOE conducts active R&D programs on many grid-related technologies, including predictive computational modeling, power electronics, grid-scale energy storage systems, and energy systems cybersecurity. Similarly, DOE conducts active R&D programs on electric-generation and -consumption technologies, such as solar PV, hydropower, electric vehicles, and energy-efficient appliances. While this report addresses metrics related to the deployment of many of these technologies in the US energy system infrastructure, it does not include a discussion of DOE technology R&D programs related to the electric grid.

2.0 Deployment Metrics and Measurements

The scope of smart grid functionality extends throughout the electricity system and its supply chain. To measure the status of smart grid deployments, multiple metrics were chosen as indicators for examining smart grid progress. Although these metrics do not comprehensively cover all aspects of a smart grid, they were chosen to address a balance of coverage in significant functional areas and to support the communication of its status through a set of smart grid attributes that have been formed through workshop engagements with industry.

2.1 Smart Grid Metrics

On June 19-20, 2008, the U.S. Department of Energy brought together 140 experts, representing the various smart grid stakeholder groups, at a workshop in Washington, DC. The objective of the workshop was to identify a set of metrics for measuring progress toward implementation of smart grid technologies, practices, and services. Breakout sessions for the workshop were organized around seven major smart grid characteristics as developed through another set of industry workshops sponsored by the NETL Modern Grid Strategy (Miller 2008). The results of the workshop document over 50 metrics for measuring smart grid progress (DOE 2008). Having balanced participation across the diverse electricity system stakeholders is important for deriving appropriate metrics and was an important objective for selecting individuals to invite to the workshop.

The workshop described two types of metrics: build metrics that describe attributes that are built in support of smart grid capabilities, and value metrics that describe the value that may be derived from achieving a smart grid. While build metrics tend to be easily quantifiable, value metrics can be influenced by many developments and therefore generally require more qualifying discussion. Both types are important to describe the status of smart grid implementation.

After reviewing the workshop results, distilling the recorded ideas and augmenting them with additional insights provided by the research team, 20 metrics were defined for the 2009 SGSR. In re-examining the original metrics, the research team viewed the 2010 SGSR as an opportunity to slightly revise rather than overhaul the original metrics. In refining the SGSR metrics based on lessons learned from the 2009 SGSR, an emphasis was placed on maintaining consistency for the sake of data continuity.

To solicit stakeholder input regarding ideas for refining the metrics presented in the SGSR, a series of stakeholder webinars was held by PNNL from May 17th through May 20th, 2010. The webinars were attended by 54 experts representing electricity service providers, standards organizations, smart grid demonstration projects, distribution service providers, telecommunications companies, products and services suppliers, and policy advocacy groups. The webinars were designed to register feedback regarding metric definition/refinement, data sources/availability, identification of relevant stakeholder groups, and regional influences. In reviewing the webinar results, several key messages were identified:

- Most metrics in the 2009 SGSR are well structured and relevant but some are in need of modification – e.g., metrics regarding cyber security, supervisory control and data acquisition (SCADA) points, and venture capital funding.
- There are several sources that could be used to close data gaps present in the 2009 SGSR, including data available through the National Association of Regulatory Utility Commissioners (NARUC) and state regulators, ARRA projects, expanded data collection through the EIA, the Smart Grid Maturity Model, and the Database of State Incentives for Renewable Energy (DSIRE).
- Numerous metrics were identified as relevant but nascent.
- A small number of metrics suffer from poor definition – e.g., metrics regarding microgrids and regulatory recovery.
- Many additional stakeholders were identified.
- The 2010 SGSR should consider adding a metric that focuses more on environmental and emissions-reduction goals.

Based on the input received through the webinars, the nascent metrics will remain in the report due to their potential as significant indicators of long-term growth in a smarter grid but will be monitored and re-evaluated for future reports. Further, a metric has been added regarding the percentage of generation through grid-connected renewable resources and the displaced CO2 emissions attributed to their presence [Metric 21–Grid-Connected Renewable Resources].

Table 2.1 lists the 21 metrics used in this report. The table includes four columns to indicate the metric's status (penetration level/maturity) and trend for both the 2009 and 2010 SGSRs. The intent is to provide a high-level, simplified perspective to a complicated picture. If it is a build metric, the penetration level is indicated as nascent (very low and just emerging), low, moderate, or high; because smart grid activity is relatively new, there are no high penetration levels to report on these metrics at the present time. If it is a value metric, the maturity of the system with respect to this metric is indicated as either nascent or mature. Build metrics describe attributes that are built in support of a smart grid, and value metrics describe the value that may be derived from achieving a smart grid. The trend (recent past and near-term projection) is indicated for either type of metric as declining, flat, or growing at nascent, low, moderate, or high levels. An investigation of the measurements for each metric can be found in Appendix A of this report.

Based on the analysis conducted in support of the 2010 SGSR, the following changes have been made to the status of metrics reported in Table 2.1:

- Metric 2 – The near-term trend for sharing real-time system operations data has been moved from moderate to high. ARRA investment is expanding the network of PMUs by 877 from the current network of 200 PMUs.
- Metric 3 – The near-term trend for standard distributed-resource interconnection policies has shifted from moderate to high as 14 states have either implemented new policies or expanded existing interconnection standards since 2008. As of June 2010, 39 states, Washington, D.C., and Puerto Rico have adopted variations of an interconnection policy. By assigning electricity service providers to states based on the location of their headquarters, it is estimated that roughly 83.9 percent of all electricity service providers in the U.S. currently have a standard resource interconnection policy in place, compared to 61 percent in 2008.
- Metric 13 – The current penetration/maturity level for advanced system measurement has been moved from low to moderate and the near-term trend has been moved to high due to the aforementioned ARRA-funded PMU projects.
- Metric 18 – Both the penetration/maturity level and the near-term trend associated with cyber security have been increased from nascent to low because, in 2008, FERC directed NERC to further tighten the critical infrastructure protection (CIP) standards to provide external oversight of critical cyber security assets, and removed language allowing variable implementation of the standards. From 306 CIP violations in July 2008, the number of CIP violations decreased to 54 in January 2010.
- Metric 19 – The near-term trend was increased from nascent to low because NIST formed the Smart Grid Interoperability Panel (SGIP) and encouraged smart grid stakeholders from all organizations associated with electric power to establish this community and advance interoperability through goals, gap analysis, and prioritized efforts designed to address the challenges to integration (Widergren et al. 2010). Following a series of 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 (NIST 2010).
- Metric 21 – The level of renewable resources excluding conventional hydro is approximately 3.5 percent of total generation but is expected to more than quadruple by 2030. Thus, the current penetration/maturity level assigned to this metric is low while the trend is moderate.

Table 2.1. Summary of Smart Grid Metrics and Status

		2009 SGSR		2010 SGSR	
#	**Metric Title** (*type: build or value*)	**Penetration / Maturity**	**Trend**	**Penetration / Maturity**	**Trend**
	Area, Regional, and National Coordination Regime				
1	Dynamic Pricing (*build*): fraction of customers and total load served by RTP, CPP, and TOU tariffs.	low	moderate	low	moderate
2	Real-time System Operations Data Sharing (*build*): total SCADA points shared and fraction of phasor measurement points shared.	moderate	moderate	moderate	high
3	Distributed-Resource Interconnection Policy (*build*): percentage of electricity service providers with standard distributed-resource interconnection policies and commonality of such policies across electricity service providers.	moderate	moderate	moderate	high
4	Policy/Regulatory Progress (*build*): weighted-average percentage of smart grid investment recovered through rates (respondents' input weighted based on total customer share).	low	moderate	low	moderate
	Distributed-Energy-Resource Technology				
5	Load Participation Based on Grid Conditions (*build*): Fraction of load served by interruptible tariffs, direct load control, and consumer load control with incentives.	low	low	low	low
6	Load Served by Microgrids (*build*): the percentage of total summer grid capacity.	nascent	low	nascent	low
7	Grid-Connected Distributed Generation (renewable and non-renewable) and Storage (*build*): percentage of distributed generation and storage.	low	high	low	high
8	EVs and PHEVs (*build*): percentage shares of on-road light-duty vehicles comprising EVs and PHEVs.	nascent	low	nascent	low
9	Grid-Responsive Non-Generating Demand-Side Equipment (*build*): total load served by smart, grid-responsive equipment.	nascent	low	nascent	low

Table 2.1. (contd)

		2009 SGSR		2010 SGSR	
#	**Metric Title** (*type: build or value*)	**Penetration / Maturity**	**Trend**	**Penetration / Maturity**	**Trend**
	Delivery (T&D) Infrastructure				
10	T&D System Reliability (*value*): SAIDI, SAIFI, MAIFI.	mature	declining	mature	declining
11	T&D Automation (*build*): percentage of substations having automation.	moderate	high	moderate	high
12	Advanced Meters (*build*): percentage of total demand served by advanced metering (AMI) customers.	low	high	low	high
13	Advanced System Measurement (*build*): percentage of substations possessing advanced measurement technology.	low	moderate	moderate	high
14	Capacity Factors (*value*): yearly average and peak-generation capacity factor.	mature	flat	mature	flat
15	Generation and T&D Efficiencies (*value*): percentage of energy consumed to generate electricity that is not lost.	mature	improving	mature	improving
16	Dynamic Line Ratings (*build*): percentage miles of transmission circuits being operated under dynamic line ratings.	nascent	low	nascent	low
17	Power Quality (*value*): percentage of customer complaints related to power quality issues, excluding outages.	mature	declining	mature	declining
	Information Networks, Finance, and Renewable Energy				
18	Cyber Security (*build*): percent of total generation capacity under companies in compliance with the NERC Critical Infrastructure Protection standards.	nascent	nascent	low	low
19	Open Architecture / Standards (*build*): Interoperability Maturity Level – the weighted average maturity level of interoperability realized between electricity system stakeholders.	nascent	nascent	nascent	low
20	Venture Capital (*value*): total annual venture-capital funding of smart grid startups located in the U.S.	nascent	high	nascent	high
21	Grid-Connected Renewable Resources (*build*): percent of renewable electricity, both in terms of generation and capacity.	None	None	low	moderate

RTP = real-time pricing; CPP = critical-peak pricing; TOU = time of use pricing; SAIDI = System Average Interruption Duration Index; SAIFI = System Average Interruption Frequency Index; MAIFI = Momentary Average Interruption Frequency Index

2.2 Smart Grid Characteristics

The 21 metrics are used to describe deployment status as organized around the six major characteristics of a smart grid identified in Table 2.2.

Table 2.2. Smart Grid Characteristics

Characteristic	Description
1. Enables Informed Participation by Customers	Consumers become an integral part of the electric power system. They help balance supply and demand and support reliability by modifying the way they use and purchase electricity. These modifications come as a result of consumers having choices that motivate different purchasing patterns and behavior. These choices involve new technologies, new information about consumers' electricity use, and new forms of electricity pricing and incentives.
2. Accommodates All Generation & Storage Options	A smart grid accommodates not only large, centralized power plants, but also the growing array of distributed energy resources (DER). DER integration will increase rapidly all along the value chain, from suppliers to marketers to customers. Those distributed resources will be diverse and widespread, including renewables, distributed generation and energy storage.
3. Enables New Products, Services, & Markets	Markets that are correctly designed and operated efficiently reveal cost-benefit tradeoffs to consumers by creating an opportunity for competing services to bid. A smart grid accounts for all of the fundamental dynamics of the value/cost relationship. Some of the independent grid variables that must be explicitly managed are energy, capacity, location, time, rate of change, and quality. Markets can play a major role in the management of these variables. Regulators, owners/operators, and consumers need the flexibility to modify the rules of business to suit operating and market conditions.
4. Provides Power Quality for the Range of Needs	Not all commercial enterprises, and certainly not all residential customers, need the same quality of power. A smart grid supplies varying grades of power and supports variable pricing accordingly. The cost of premium power quality (PQ) features can be included in the electricity service contract. Advanced control methods monitor essential components, enabling rapid diagnosis and precise solutions to PQ events, such as arise from lightning, switching surges, line faults and harmonic sources. A smart grid also helps buffer the electricity system from irregularities caused by consumer electronic loads.
5. Optimizes Asset Utilization & Operating Efficiency	A smart grid applies the latest technologies to optimize the use of its assets. For example, optimized capacity can be attainable with dynamic ratings, which allow assets to be used at greater loads by continuously sensing and rating their capacities. Maintenance efficiency involves attaining a reliable state of equipment or "optimized condition." This state is attainable with condition-based maintenance, which signals the need for equipment maintenance at precisely the right time. System-control devices can be adjusted to reduce losses and eliminate congestion. Operating efficiency increases when selecting the least-cost energy-delivery system available through these adjustments of system-control devices.
6. Operates Resiliently to Disturbances, Attacks, & Natural Disasters	Resilience refers to the ability of a system to react to events such that problematic elements are isolated while the rest of the system is restored to normal operation. These self-healing actions result in reduced interruption of service to consumers and help service providers better manage the delivery infrastructure. A smart grid responds resiliently to attacks, whether the result of natural disasters or organized by others. These threats include physical attacks and cyber attacks. A smart grid addresses security from the outset, as a requirement for all the elements, and ensures an integrated and balanced approach across the system.

2.3 Mapping Metrics to Characteristics

Section 3 of the report describes the status of smart grid deployment using the six characteristics presented in Table 2.2. A map of how the 21 metrics support the six characteristics is shown in Table 2.3. Notice that nearly every metric contributes to multiple characteristics. To reduce the repetition of statements about the metrics, each metric was assigned a primary characteristic for emphasis. The table indicates the characteristic in which a metric is emphasized as “emphasis.” The other characteristic cells where a metric plays an important but not primary role are indicated by “mention.” This should not be interpreted to be of secondary importance, only that a metric finding is mentioned under the characteristic in order to reduce redundancy of material in explaining the status of smart grid deployment.

Table 2.3. Map of Metrics to Smart Grid Characteristics

Metric No.	Metric Name	Enables Informed Participation by Customers	Accom-modates All Generation & Storage Options	Enables New Products, Services, & Markets	Provides Power Quality for the Range of Needs	Optimizes Asset Utilization & Efficient Operation	Operates Resiliently to Disturbances, Attacks, & Natural Disasters
1	Dynamic Pricing	Emphasis	Mention	Mention			Mention
2	Real-Time Data Sharing					Mention	Emphasis
3	DER Interconnection	Mention	Emphasis	Mention		Mention	
4	Regulatory Policy			Emphasis			
5	Load Participation	Emphasis			Mention	Mention	Mention
6	Microgrids		Mention	Mention	Emphasis		Mention
7	DG & Storage	Mention	Emphasis	Mention	Mention	Mention	Mention
8	Electric Vehicles	Mention	Mention	Emphasis			Mention
9	Grid-responsive Load	Mention	Mention	Mention	Mention		Emphasis
10	T&D Reliability						Emphasis
11	T&D Automation				Mention	Emphasis	Mention
12	Advanced Meters	Emphasis	Mention	Mention			Mention
13	Advanced Sensors						Emphasis
14	Capacity Factors					Emphasis	
15	Generation, T&D Efficiency					Emphasis	
16	Dynamic Line Rating					Emphasis	Mention
17	Power Quality			Mention	Emphasis		
18	Cyber Security						Emphasis
19	Open Architecture/Stds.			Emphasis			
20	Venture Capital			Emphasis			
21	Renewable Resources		Emphasis	Mention	Mention	Mention	

3.0 Deployment Trends and Projections

Deploying a smart grid is a journey that has been underway for some time, but will accelerate because of EISA, ARRA, and the recognition of characteristics and benefits collected and emphasized under the term "smart grid." Though there has been much debate over the exact definition, a smart grid comprises a broad range of technology solutions that optimize the energy value chain. Depending on where and how specific participants operate within that chain, they can benefit from deploying certain parts of a smart grid solution set. Based on the identification of deployment metrics, this section of the report presents recent deployment trends. In addition, it reviews plans of the stakeholders relevant to smart grid deployments to provide insight about near-term and future directions.

The status of smart grid deployment expressed in this section is supported by an investigation of 21 metrics obtained through available research, such as advanced metering and T&D substation-automation assessment reports, penetration rates for energy resources, and capability enabled by a smart grid. In each section, the emphasis is placed on data and trends registered since the 2009 SGSR was completed. In each subsection that follows, the metrics contributing to explaining the state of the smart grid characteristic are called out so the reader may review more detailed information in Appendix A. The metrics emphasized to explain the status of a characteristic are highlighted with an asterisk (*).

3.1 Enables Informed Participation by Customers

A part of the vision of a smart grid is its ability to enable informed participation by customers, making them an integral part of the electric power system. With bi-directional flows of energy and coordination through communication mechanisms, a smart grid should help balance supply and demand and enhance reliability by modifying the manner in which customers use and purchase electricity. These modifications can be the result of consumer choices that motivate shifting patterns of behavior and consumption. These choices involve new technologies, new information regarding electricity use, and new pricing and incentive programs.

A smart grid adds consumer demand as another manageable resource, joining power generation, grid capacity, and energy storage. From the standpoint of the consumer, energy management in a smart grid environment involves making economic choices based on the variable cost of electricity, the ability to shift load, and the ability to store or sell energy.

Consumers who are presented with a variety of options when it comes to energy purchases and consumption are enabled to:

- respond to price signals in order to make better-informed decisions regarding when to purchase electricity, when to generate energy using distributed generation, and whether to store and reuse it later with distributed storage.
- make informed investment decisions regarding more efficient and smarter appliances, equipment, and control systems.

Related Metrics
1*, 3, 5*, 7, 8, 9, 12*.

3.1.1 Grid-Enabled Bi-Directional Communication and Energy Flows

A major element of smart grid implementation projects continues to be the deployment of advanced meters and their supporting infrastructure, or AMI, with ever-increasing numbers of service providers completing pilot programs and moving toward full AMI deployment [Metric 12–Advanced Meters]. In addition, ARRA allocated $3.4 billion in grants to invest in smart grid technologies and electricity transmission infrastructure, with total investment of $8.2 billion including private sector contributions (DOE 2009a).

Smart grid system implementation relies on a variety of AMI technologies that provide two-way communication between the customer and electricity service provider. Figure 3.1 illustrates the flow of metering data between the consumer Home Area Network (HAN), AMI technologies, such as smart meters or gateways, and IT systems. HAN communications access AMI data and can also serve as the gateway from the electricity service provider to the meter. This communication system can operate through wired, wireless, open or proprietary networks and supply/communicate information for a variety of consumer and electricity service provider applications such as energy awareness, demand response, and DG.

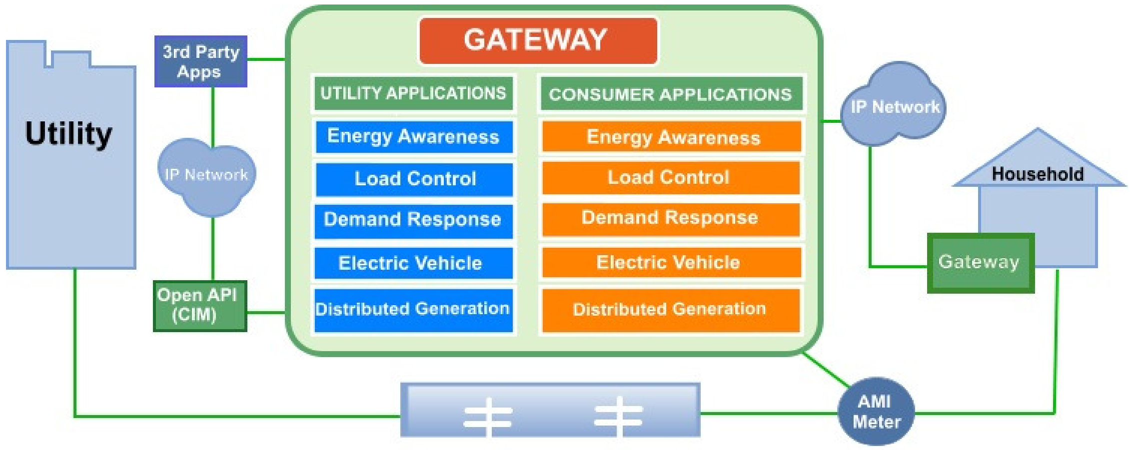


Figure 3.1. Overview of AMI Interface (Tendril 2010)

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

The number of advanced meters installed in the U.S. has grown dramatically in recent years from approximately 0.9 million (0.7 percent of all residential meters) in 2006 to 7.95 million in 2009 (FERC 2009b). AMI deployment schedules have accelerated since the passage of ARRA. Federal grant awards for AMI deployments under ARRA total $812.6 million to date, with total project values reaching over $2 billion (DOE 2010a). The states with the most significant AMI investments under ARRA include Texas, Maryland, Maine, and Arizona; however, projects are being undertaken by electricity service providers located in 19 states (FERC 2009b).

Data on AMI penetration were obtained from the Cleantech Group (Neichin and Cheng 2010) and the EMeter Corporation. Based on data provided by both sources, AMI deployments nationwide have expanded to an estimated 16 million in 2010, representing 10.7 percent of U.S. electricity meters. State public utility commissions (PUCs) have approved an additional 34 million AMI deployments. Installed and approved AMI deployments identified by EMeter (King 2010) are presented in Table 3.1.

Table 3.1. Installed and Planned Smart Meters

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	Baltimore Gas and Electric Company	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

Demand response technologies, which involve bi-directional flows of information between home equipment and the grid, hold promise for reducing peak demand. An evaluation conducted by FERC found that demand response technologies hold the potential to reduce peak demand by 14 to 20 percent by 2019 under achievable and full-participation scenarios, respectively (FERC 2009a). A significant portion of peak-demand reductions rely on electricity service providers offering dynamic pricing tariffs, which require enabling technologies such as smart meters and communicating thermostats [Metric 1–Dynamic Pricing]. Generally, these tariffs take the following forms:

- Time of use (TOU). Under TOU, prices are differentiated based solely on a peak versus off-peak period designation, with prices set higher during peak periods. TOU pricing is not dynamic because it does not vary based on real-time conditions. It is included here, though, because it is viewed as an intermediate step toward a more dynamic real-time pricing (RTP) tariff.
- Critical peak pricing (CPP). Under a CPP tariff, the higher critical-peak price is restricted to a small number of hours (e.g., 100 of 8,760) each year, with the peak price being set at a much higher level relative to normal conditions.

- Real-time pricing. Under RTP, hourly prices vary based on the day-of (real time) or day-ahead cost of power to the electricity service provider.

FERC conducts biennial interviews regarding demand response initiatives, pricing tariffs, and AMI deployments. In 2008, the FERC questionnaire was distributed to 3,407 organizations in all 50 states. In total, 100 electricity service providers that responded reported offering some form of RTP tariff to enrolled customers, as compared to 60 in 2006 (Table 3.2). FERC also found through these interviews that 315 electric service providers nationwide offered TOU rates, compared to 366 in 2006. In 2008, 241 of the 315 electricity service providers with TOU rates reported offering those rates to residential customers. In those participating electricity service providers, approximately 1.3 million customers were signed up for TOU tariffs, representing 1.1 percent of all residential homes. In 2008, customers were enrolled in CPP tariffs offered by 88 electricity service providers, as compared to 36 in 2006. The programs reported in Table 3.2 include those offered to residential, commercial, and industrial customers.

Table 3.2. Number of Entities Offering and Customers Served by Dynamic Pricing Tariffs (FERC 2008)

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%

Electricity service providers interviewed for this report were asked two questions related 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 offered TOU plans.
- No companies offered CPP plans.
- One company (4.2 percent) indicated they had both dynamic price plans and the ability to send price signals to customers.

The respondents were also asked whether their electricity service provider had automated responses to pricing signals for major energy using devices within the premises. Responses were as follows:

- 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.

The results of recent voluntary programs suggest that the impact of dynamic pricing could be significant. 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 (George et al. 2010). The program raised rates incrementally during the afternoon peak period (2 p.m. to 7 p.m.) up to as high as $.60 per kWh for residential customers and $.75 per kWh for non-residential customers (George et al. 2010). 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 (George et al. 2010). Participants were offered bill protection, credits and financial incentives (gift cards) for enrollment.

In the future, as EVs and PHEVs penetrate the U.S. light-duty vehicle market, these alternative-fuel vehicles could also advance load shifting through their energy storage capabilities [Metric 8–EVs and PHEVs]. Vehicle-to-grid (V2G) software could be used to perform several functions while vehicles are connected to the grid: (i) adjust the timing and pace of charging to meet the needs of the customer while minimizing the demand placed on the grid; (ii) upload real-time performance data and vehicle information such as the car battery's size, current state of charge, elapsed time since the last charge, and vehicle miles traveled (VMT); and (iii) enable EVs to charge during periods of low demand and return stored energy back to the grid during peak periods. Several pilot tests are being conducted across the U.S. to examine various charging management strategies. These tests include:

- Idaho National Laboratory (INL) is leading a field test of 57 PHEVs with the objective of capturing real-time data from vehicles in Washington, Oregon, California, and Hawaii.
- Seattle City Light is operating a field test on 13 Toyota Priuses to examine the impact of a PHEV fleet deployed in an urban environment.
- Duke Energy, Progress Energy, and Advanced Energy are leading a field test involving the smart charging of 12 Toyota Priuses to examine the requirements for supporting vehicles as they roam between service areas (V2 Green 2010).

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 (Gerkensmeyer et al. 2010, Onar and Khaligh 2010). 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.

In 2008, EIA reported that 9,591 service provider- or customer-owned distributed generators were grid-connected, representing a total capacity of 12,863 megawatts (MW) (EIA 2008). In addition, EIA reported 12,262 dispersed generators (not grid-connected), representing 9,773 MW. When compared to 2006 levels, the number of distributed and dispersed generators has grown by 90.1 percent and 28.6 percent, respectively [Metric 3–Distributed-Resource Interconnection Policy].

DG has the capacity to help alleviate peak load, provide needed system support during emergencies, and improve power quality and reliability [Metric 7–Grid-Connected Distributed Generation]. Service providers that facilitate the integration of these resources and use them effectively could realize considerable cost savings over the long-term.

Consumer participation in DG can be facilitated with agreed-upon policies for interconnection to the grid. As of June 2010, 39 states, Washington D.C., and Puerto Rico have adopted variations of interconnection policies. Since 2008, 14 states have either implemented new policies or expanded interconnection standards, representing 83.9 percent of electricity service providers in the U.S. This is an increase of 22.9 percent since the previous SGSR was released in 2009.

The presence of an interconnection policy, however, does not necessarily indicate that the policy is favorable to electricity consumers or even equitable to both parties. 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 advancement of DER. The grading system designed by IREC and NNEC numerically evaluated 14 policy issues specific to interconnection, including: technological considerations, system capacity, cost effectiveness, insurance requirements, and timelines (NNEC 2009). Based on interconnection standards measured by IREC and NNEC, 13 states have policies favorable to grid interconnection, 15 states have neutral policies and 22 states (including those with no standard) have unfavorable policies [Metric 3–Distributed-Resource Interconnection Policy].

3.1.2 Managing Supply and Demand

Simple measures, such as turning off or adjusting water heaters, dishwashers, and heating and cooling systems, result in load shifting and reduced costs through the smoothing of peak power consumption throughout the day. With appropriate metering capability in place, dynamic pricing signals received by customers can enable demand response.

Traditionally, demand participation has principally taken place through interruptible demand and direct-control load-management programs implemented and controlled by electricity suppliers. While many organizations (e.g., Electric Reliability Council of Texas (ERCOT), Public Utility Commission of Texas (PUCT), and ISOs in California and New York) act to balance and curtail load in order to avoid and manage brownouts and blackouts, load management participation is very low nationally, as indicated in Figure 3.2.

Figure 3.2 demonstrates that load management has not historically played a strong role in energy markets. Nationally, load management as a percentage of net summer capacity was 1.3 percent in 2008. The trend has been somewhat volatile over the past decade but has appeared to follow an upward trend since 2003. According to the EIA, load management in 2008 reached 13,091 MW (EIA 2010f). Thus, less than 2 percent of net summer capacity is under load management programs [Metric 5–Load Participation Based on Grid Conditions].

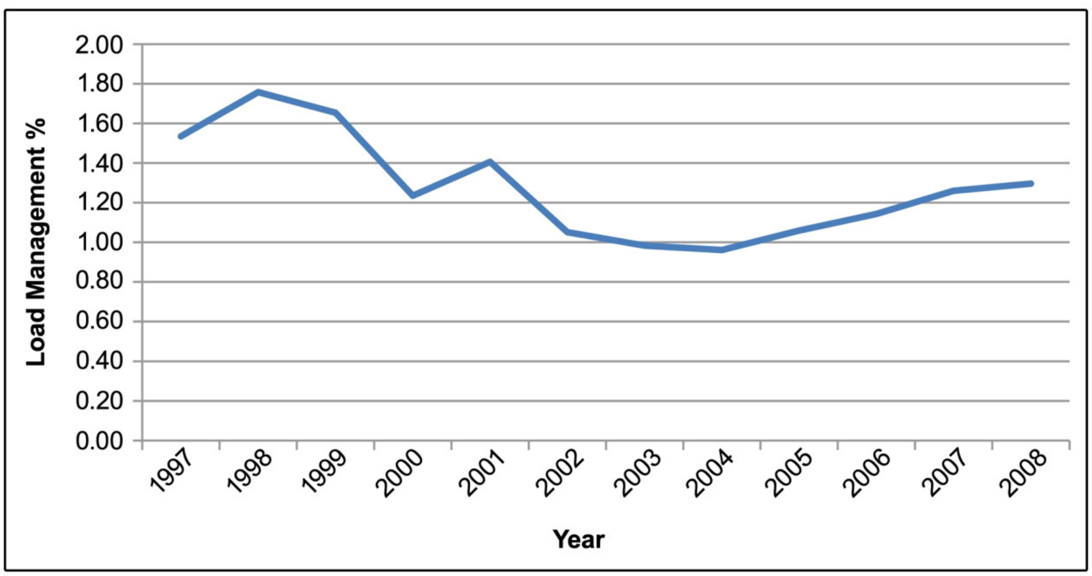


Figure 3.2. National Historic Demand-Response and Load-Management Peak Reduction as a Percentage of Summer Net Capacity

Despite the load management shares presented in Figure 3.2, FERC forecasts growth in demand-response programs under its business-as-usual (BAU) case, with peak demand reductions reaching 38 GW, or 4 percent, by 2019. Demand can also be managed through engaging appliances, thermostats, and other equipment that hold the potential to be responsive to the dynamic needs of the electricity system. Products have emerged and continue to evolve in this category that either directly monitor or receive communicated recommendations from system operators. 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 (Palmgren et al. 2010). Based on EIA electricity customer data, the forecast penetration rate corresponds to approximately 3.7 million electricity customers in California with communicating thermostats in 2009. Progress is being made with “smart” appliances as well. 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. Further, Whirlpool expects to make all appliances smart grid capable by 2015 (Zpryme Research and Consulting 2010). [Metric 9–Grid-Responsive Non-Generating Demand-Side Equipment]. Although markets for these products are still nascent, deployment of smart grid technologies, infrastructure and policies will enhance penetration of demand-response devices.

Though dynamic-pricing and demand-response programs have historically been responsible for modest levels of load shifting, current research suggests that there is significant potential for the programs to manage supply and demand in the future. A recent study sponsored by EPRI and the Edison Electric Institute (EEI) estimated that 37 percent of the growth in electricity sales (419 TWh) between 2008 and 2030 could be offset through energy-efficiency programs and 52 percent of peak demand growth (164 GW of capacity) could be offset by a combination of energy-efficiency and demand-response programs. More specifically, approximately 2,824 MW of peak demand was forecasted to be offset by 2010 through price-responsive policies, 13,661 MW of peak demand could be offset through price response by 2020, and 24,869 MW could be offset by 2030. The largest share of the price-response benefits are forecast to take place in the residential sector (10,838 MW or 43.6 percent of the offset in 2030), with the commercial sector (8,350 MW or 33.6 percent of the offset in 2030) and industrial sector (5,681 MW or 22.8 percent of the offset) trailing behind (Rohmund et al. 2008). Figure 3.3 illustrates the potential savings from demand-response and energy-efficiency programs by sector, as estimated by EPRI and EEI.

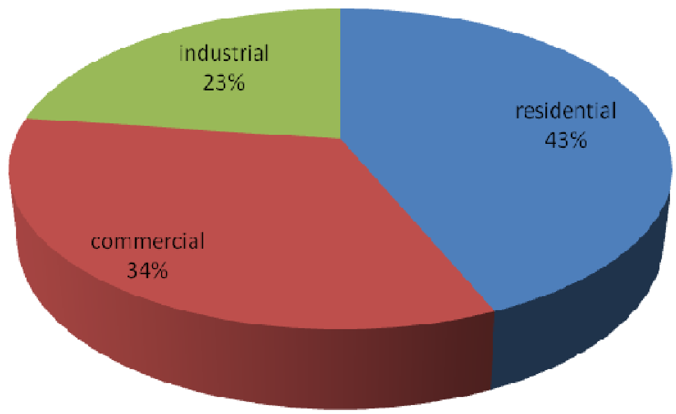


Figure 3.3. 2030 Forecast Demand Response and Energy Efficiency Peak Demand Offsets by Sector

3.2 Accommodating All Generation and Storage Options

Central to the concept of a smart grid is the ability to accommodate a range of diverse generation types including centralized and distributed generation, as well as diverse storage options. Using different generation and storage types, a smart grid can better meet consumer load demand, as well as accommodate intermittent renewable energy technologies. Specifically, distributed resources can help meet peak demand, supply needed system support during emergencies, and reduce the costs of power. Accommodating the wide range of options available to transmission providers, distribution entities, and end users requires an environment similar to the computer industry's "plug and play" environment (DOE 2008).

The primary metrics of progress for this characteristic include the amount of grid-connected DG and storage, progress in connecting diverse generation types, a standard distributed-resource connection policy, and grid-connected renewable resources. There are a number of other metrics (e.g., microgrids, electric vehicles, AMI) that also describe the current status of a smart grid to accommodate all generation and storage options, and these metrics are also addressed in this section of the report.

Related Metrics
1, 3*, 6, 7*, 8, 9, 12, 21*.

Measures of DG [Metric 7–Grid-Connected Distributed Generation] and the interconnection standards policies [Metric 3–Distributed Resource Interconnection Policy] are moving in positive directions. DG systems are smaller-scale, local power generation (10 MVA or less) that can be connected to primary and/or secondary distribution voltages as compared to the larger, more centralized generation that provides most of the grid's power (IEEE 2003). Incentives to promote installation of such systems are becoming more common at the state level. In November and December 2010 alone, 20 states instituted new incentive policies or expanded existing ones (DSIRE 2010a). Solar cells, solar thermal electricity systems, wind turbines and biomass applications are some of the options available to residential and rural consumers. Batteries, flywheels and thermal storage units that can be used to store energy are also included in this category.

Other measures that affect this category include dynamic pricing [Metric 1], microgrids [Metric 6–Load Served by Microgrids], market penetration of EVs and PHEVs [Metric 8], grid-responsive, non-generating demand-side equipment [Metric 9], advanced meters [Metric 12] and grid-connected renewable resources [Metric 21]. Each measure plays a unique role in accommodating all generation and storage. The microgrid metric still remains nascent and largely unmeasured. EVs, another source of distributed resources, reached almost 27 thousand vehicles on the road in 2008 or almost 0.01 percent of light-duty vehicles. Demand-side equipment is a nascent metric and is still unmeasured at this time. Grid-connected renewable resources [Metric 21] include more than DG, as wind farms and other large but decentralized sources of generation are also encompassed within this category. Currently, renewable resources excluding conventional hydro have reached more than 3.5 percent of total generation and total output is expected to more than quadruple by 2030.

A wide range of stakeholders including end users, service providers, regulators, manufacturers, distribution service providers and third party developers must be accommodated in order to attain all the generation and storage options available. Appropriate consideration will need to be given to each stakeholder's interest to support the appropriate evolution of the electricity system while improving efficiency of grid resources (DOE 2008). For example, stakeholders associated with development of generation and storage systems and other technologies will need to recoup their investments and must have clear incentives in order to initiate projects. Storage device life-cycle benefits must be greater than costs and pricing approaches need to be structured to provide the benefits to owners. Similarly, while distributed generation offers benefits in terms of electricity generation plant investment cost avoidance to power producers, end users need to see the additional benefits, including greater reliability and less environmental impact, when compared with traditional fossil fuel systems. In some cases, utilities or regulators even impose fees upon the owner when DG often saves the utility money in deferred upgrades, reduced losses, and avoidance of wholesale purchases to cover demand (Gil and Joos 2008). Both end users and service providers must recover their investments in distributed resources, smart meters, and other smart grid accessories that allow the grid resources and entities to communicate and respond to changing grid conditions (NETL 2007). The following sections describe in more detail distributed generation and storage, and interconnection standards.

3.2.1 Distributed Generation and Storage

Distributed generation capacity [Metric 7–Grid-Connected Distributed Generation] continues to be a small part of total power generation even though it has been steadily increasing over the years. Total DG capacity reached 5,423 MW in 2004, then grew to 12,863 MW in 2008, an increase of 137 percent (Figure 3.4) (EIA 2010a). With the recession in 2008, electricity generation and sales were adversely affected by the weakening economy as net electric power generation decreased for the first time since 2001, dropping 0.9 percent from 4,157 million megawatt-hours (MWh) in 2007 to 4,119 million MWh in 2008. Non-coincident summer peak load fell by 3.8 percent, from 782,227 MW in 2007 to 752,470 MW in 2008. Non-coincident winter peak load increased in 2008 by 0.9 percent, from 637,905 MW in 2007 to 643,557 MW in 2008 (EIA 2010a).

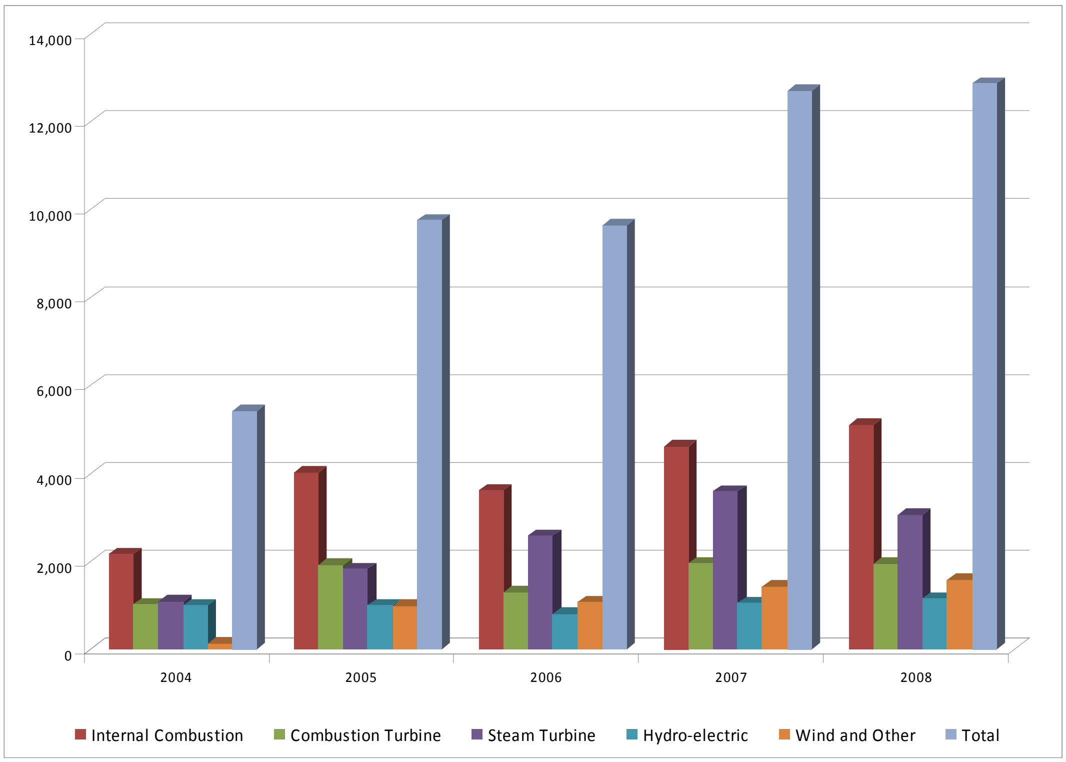


Figure 3.4. Yearly Installed DG Capacity by Technology Type (EIA 2010c)

Actively managed fossil-fired, small hydro, and biofuels DG capacity reached 10,121 MW in 2008, up 136 percent from 2004, representing approximately 1.3 percent of total generating capacity and 78 percent of total DG (Table 3.3). Wind and other renewable energy sources (RESs) grew significantly between 2004 and 2008, increasing by 1,051 percent. That level represents only 0.16 percent of total available generating capacity, 0.21 percent of summer peak capacity, and 0.24 percent of winter peak (EIA 2010c). Distributed wind is very small in comparison to central wind farms, which had nearly 23,000 MW of capacity. Intermittent renewable-energy resources such as wind may not be effective sources for meeting peak demand, although solar has the potential to be more coincident with summer peak-demand periods.

Interviews conducted in support of this study indicated the following about grid-connected DG:

- The capacity to support DG (connect and use DG) is 23.7 percent of total grid capacity.
- Storage capacity comprised of approximately 0.9 percent of total customers.
- Non-dispatchable renewable generation was reported by 5.7 percent of total customers, compared to 1.4 percent measured for the 2009 SGSR.

Table 3.3. Yearly Installed DG Capacity by Technology Type (EIA 2010c)

Capacity of Distributed Generators by Technology Type , 2004 through 2008 (Count, Megawatts)							
	Internal Combustion	Combustion Turbine	Steam Turbine	Hydroelectric	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 by either the customers of the distribution service provider or by the electricity service provider. Other Technology includes generators for which technology is not specified.

Some DG systems have large startup costs for customers. For example, solar panels can be easily installed on rooftops by homeowners and safely generate power for years. However, solar power installed in this way can have a cost of $6 per watt (NREL 2010), although in the future these costs could become much lower even including installation (Next Energy News 2007). Cost reductions are expected as DG capacities grow. More specifically, the costs for DG technologies are expected to fall by 10 percent for each of the first three doublings of capacity, 5 percent during the next five doublings of capacity, and finally by 2.5 percent for all subsequent capacity doublings (Eynon 2002).

3.2.2 Standard Distributed-Resource Connection Policy

The increasing presence of DER has led to various efforts to standardize the process of interconnecting these resources with the grid. Federal legislation attempting to deal with the issue emerged in progressively stronger language, resulting in the Energy Policy Act of 2005 (EPACT 2005), which requires all state and non-state electricity service providers to consider adopting interconnection standards based on the Institute of Electrical and Electronics Engineers (IEEE) Standard 1547 (42 USC 15801). IEEE 1547, published in 2003, looks strictly at the technical aspects of DER interconnection, providing a standard that limits the negative effects of these resources on the grid (Cook and Haynes 2006). Currently, IEEE is working on Standards 1547.6 and 1547.8, which will expand the functional requirements for DER interconnection.

To expand favorability of interconnection standards, EISA mandated interoperability policies to accommodate consumer distributed resources, including DG, renewable generation, energy storage, energy efficiency and demand response (110 USC 1305). By June 2010, 39 states as well as Washington, D.C. and Puerto Rico adopted variations of an interconnection policy [Metric 3–Distributed Resource 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. The percentage of electricity service providers with standard resource-interconnection policies was based on whether the individual electricity service providers matched their state's interconnection policies. Roughly 83.9 percent of electricity service providers currently have a standard resource-interconnection policy in place, compared with 61 percent in 2008 (NNEC 2009).

States differ significantly in their approach to interconnection standards. Nine states plus Puerto Rico have no limits on the size of generation systems 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 (Figure 3.5). Many states that have taken aggressive action on DG have done so to incorporate grid-connected renewable energy to meet renewable portfolio standards or energy efficiency requirements.

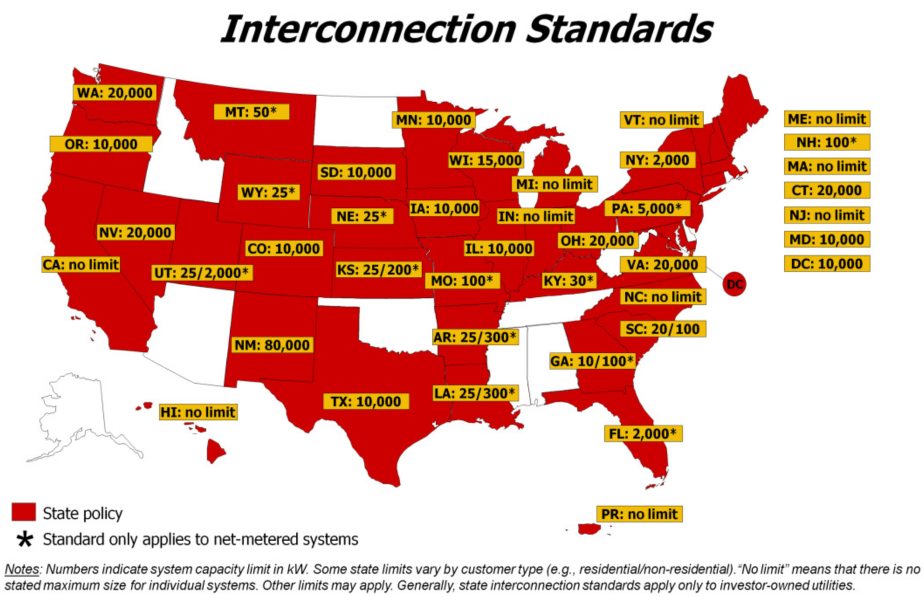


Figure 3.5. State Interconnection Standards (DSIRE 2010b)

In order for interconnection standards to be acceptable to end users, states should draft them in a manner that encourages consumer participation. The IREC and the NNEC analyzed the favorability of state interconnection standards in 2009 based on a 14-point numerical grading system that awarded points for active promotion and deducted points for discouraging DER advancement (NNEC 2009). Previously, the 2009 SGSR used research conducted as part of EPA's clean energy programs. EPA conducted a similar study in 2008, which was used to evaluate the favorability of interconnection standards for distributed generation. The EPA based their favorability standards on six factors that affect interconnection policy. Table 3.4 illustrates the difference between the IREC/NNEC and EPA favorability scoring categories.

Table 3.4. Favorability Scoring Categories

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

Rule Coverage	

Figure 3.6 presents the favorability of interconnection standards in each state according to the IREC and NNEC study. The A-F grading system used in the IREC and NNEC study was established on the basis of the categories listed in Table 3.4 to reflect positive or negative implementation characteristics for each component. The IREC and NNEC study found that 13 states have favorable policies, 15 states have neutral policies and 22 states (including those with no standard) have unfavorable policies for grid interconnection. 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 (NNEC 2009). The IREC and NNEC study indicated significantly more states had unfavorable standards.

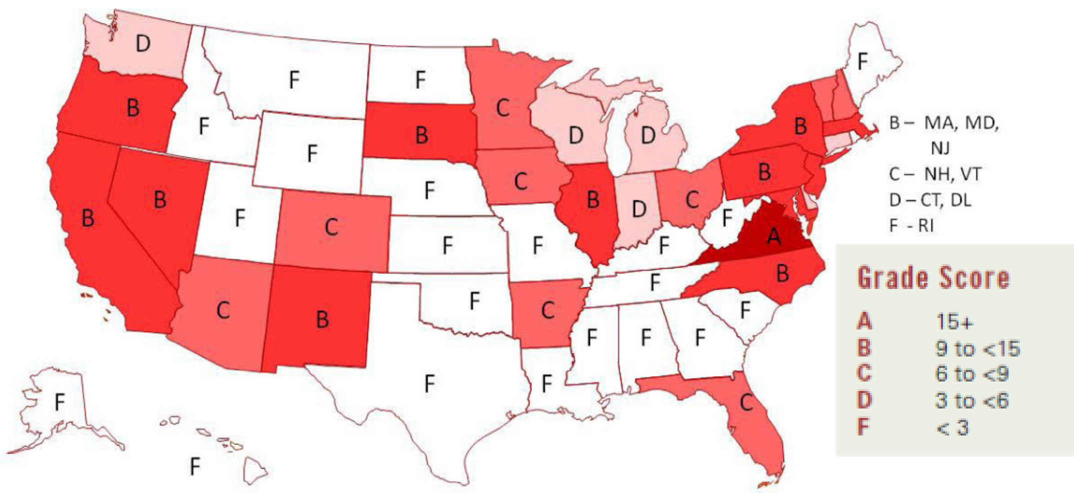


Figure 3.6. Favorability of State Interconnection Standards According to IREC and NNEC

3.3 Enables New Products, Services, and Markets

Energy markets that are correctly designed and operated can efficiently reveal benefit-cost tradeoffs to consumers by creating an opportunity for competing services to bid. A smart grid enables a more dynamic monitoring of the value/cost relationship by acquiring real-time information, conveying information to consumers, and supporting variable pricing policies that promote consumer responses to price signals. Some of the grid variables that must be explicitly managed are energy, capacity, location, time, rate of change, and quality. Markets can play a major role in the management of those variables. Regulators, owner/operators, and consumers need the flexibility to modify the rules of business to suit operating and market conditions.

Related Metrics

1, 3, 4*, 7, 8*, 9, 12, 17, 19*, 20*, 21.

Smart grid investments are often capital intensive and include multiple jurisdictions within an electricity provider's service area. Thus, 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) and enable numerous new products (e.g., PHEVs, smart appliances, solar panels), such benefits may be difficult to quantify and build into existing business cases.

To address current regulatory and financial barriers to smart grid implementation, Congress has responded with legislation designed to encourage development of new, advanced technologies in the energy sector. In 2009, ARRA designated $4.5 billion in funding for electric grid modernization programs, including $3.4 billion for the Smart Grid Investment Grant (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. Figure 3.7 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.

IG represents ARRA-funded smart grid investment grant projects (SGIG)

DP represents ARRA-funded smart grid demonstration projects (SGDP)

OP represents other projects

Figure 3.7. ARRA and Non-ARRA Smart Grid Investment Grant and Demonstration Projects (SGIC 2010)

3.3.1 Enabling New Products and Services

A smart grid enables new products and services through automation, communication sharing, facilitating and rewarding shifts in customer behavior in response to changing grid and market conditions, and its ability to encourage development of new technologies (e.g., AMI, PHEVs). A smart grid enables grid-responsive equipment, including communicating thermostats, microwaves, clothes washers and dryers, and water heaters [Metric 9–Grid-Responsive Non-Generating Demand-Side Equipment]. On November 4th, 2009, Reliant Energy and General Electric (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 could employ smart-grid-connected washing machines, dryers, and refrigerators to manage their home energy use (Ordans News 2010). GE (2009) has also been working with Louisville Gas and Electric (LG&E) over the past year on a joint smart grid demonstration project in Louisville, Kentucky, to test the interaction between smart appliances and smart meters under dynamic pricing conditions.

A smart grid that incorporates real-time pricing structures and bi-directional information flow through metering and information networks is expected to support the introduction of numerous technologies into the system. Enabling AMI technology itself represents a major driver in smart grid investment, as evidenced by several large-scale deployment programs [Metric 12–Advanced Meters]:

- 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 (CPUC 2009).
- DTE Energy (2009), operating in Michigan, invested $84 million to install 0.7 million smart meters in their service area in 2010.
- American Electric Power (AEP), 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 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.
- Southern California Edison (SCE) plans to install 5 million meters by 2012 (SCE, undated).
- Connecticut Light & Power (CL&P) (2010) will offer dynamic pricing programs through AMI to 1.2 million customers beginning in 2012.

A smart grid also supports the deployment of new vehicle technologies (EVs and PHEVs) [Metric 8–EVs and PHEVs]. The various features of a smart grid, including bidirectional metering and dynamic pricing, could feasibly enhance the customer's return on investment (ROI) for EV and PHEV technologies and accelerate market penetration. Furthermore, smart grid elements support financial incentives that could lead to a shift in charging off-peak, which could reduce the need for additional investments in energy infrastructure and enhance infrastructure asset utilization rates as more EVs and PHEVs are put into operation. Thus, the market penetration of EVs and PHEVs demonstrates the potential application of new technologies enabled by smart grid capabilities.

Table 3.5 shows that the number of EVs reached 26,823 in 2008, representing roughly .01 percent of all light-duty vehicles in use. Light-duty vehicles include automobiles, vans, pickups, and sport utility vehicles (SUVs) with a gross vehicle weight rating of 8,500 pounds or less.[2] Annual 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. PHEV's in use are forecast by DOE to reach 3.3 million (1.2 percent of all light-duty vehicles) by 2030 (EIA 2010d).

[2] 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.

Table 3.5. EV and PHEV Market Penetration (EIA 2010d)

Year	EVs On-Road		PHEVs On-Road		EV Sales		PHEV Sales	
	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%

Customer acceptance of EVs and PHEVs will soon be put to the test with the newly introduced Nissan Leaf, which has a 100-mile all-electric range, the Tesla Roadster, and the 2011 Chevrolet Volt, which is a PHEV with an all-electric range of 40 miles. In addition to the Volt, there are several companies that perform aftermarket PHEV conversions, including Amberjac Systems, Hybrids-Plus, Plug-In Conversions Corp., and Hymotion. Additionally, ARRA funded $2.4 billion in grant awards for electric vehicle battery development, component manufacturing and transportation electrification (DOE 2009c). Grants were awarded to 48 projects conducted by private manufacturing companies, universities and automotive corporations.

The U.S. DOE forecast presented in the 2010 Annual Energy Outlook (AEO) is very conservative compared to a number of recent forecasts prepared by industry. While some forecasts estimate ultimate EV and PHEV penetration in the 8 to 16 percent range, more recent forecasts that use more aggressive assumptions regarding public investment in R&D, advancements in battery technology, oil prices, and tax incentives for consumers have estimated PHEV market penetration rates as high as 60 to70 percent of the light duty vehicle market by 2030. For example, the EPRI and Natural Resources Defense Council (NRDC) estimated 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 (EPRI et al. 2007).

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 3.8. Note that for several studies, there are multiple estimates 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. Each of the studies identified in Figure 3.8 is examined in more detail under Metric 8 in Appendix A of this report.

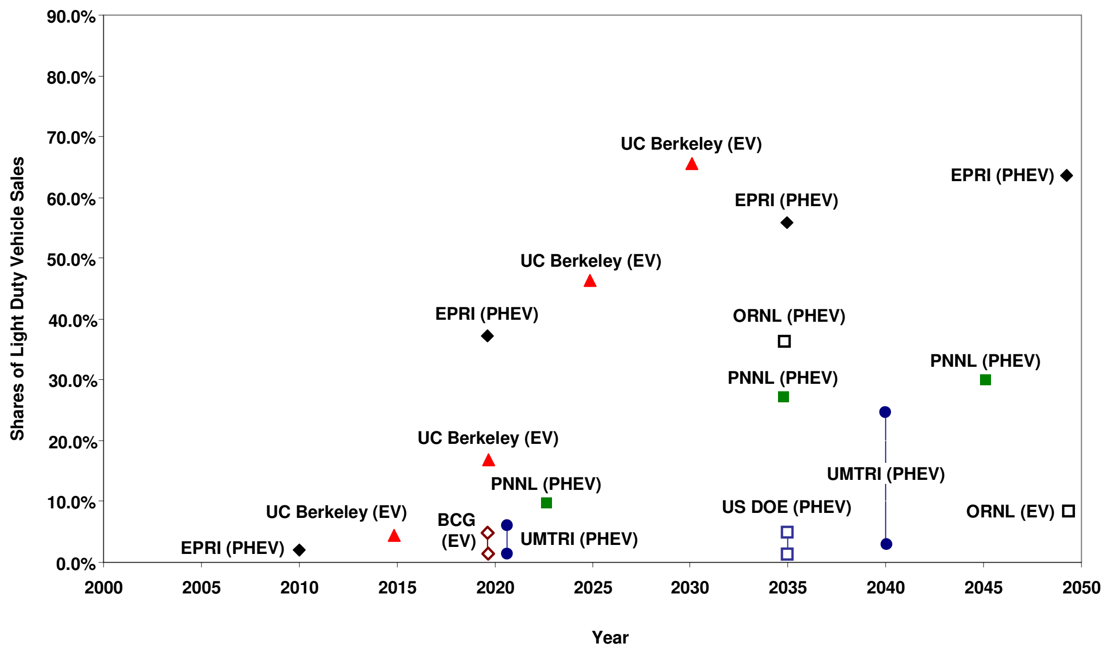


Figure 3.8. PHEV Market Penetration Scenarios

A number of other technologies are commercially available that take advantage of smart grid features. For example, in 2008, EIA reported that 9,591 utility- or customer-owned DG units were grid-connected, representing a total capacity of 12,863 MW (EIA 2008). In addition, the EIA reported 12,262 dispersed generators (not grid-connected), representing 9,773 MW for owners/operators of a distribution system [Metric 3–Distributed Resource Interconnection Policy].

3.3.2 Enabling New Markets

A smart grid supports a more efficient allocation of resources through the use of information systems enabling communication between the grid and "smart" appliances, DG units, and other consumer-oriented devices. Further, a smart grid rewards customers who engage in load-shifting behavior through the use of advanced meters, communication of real-time usage and price information, and incentive structures. Market-based approaches are expected to effectively manage these resources and reduce costs to consumers and service providers.

The new products, services, and markets highlighted in this section depend on regulatory recovery for smart grid investments. Historically, regulated electricity service providers have been rewarded for investment in capital projects and energy throughput. That is, expanded peak demand has driven the need for additional capital projects, which increase the rate base. As energy sales grow, revenues increase. Both factors run counter to encouraging smart grid investments. Thus, regulatory frameworks can discourage energy efficiency, demand reduction, demand response, DG, and asset optimization.

Rate adjustments can be encouraged through the policy of decoupling, which breaks the link between the amount of energy sold by a regulated electricity service provider and the revenue it collects [Metric 4–Regulatory Recovery]. Breaking this link ensures that electricity service providers will recover the fixed costs approved by their regulatory commission, including an approved rate of return on investment, regardless of sales volume. The most common decoupling policies include:

- Full decoupling—An electricity service provider recovers the allowed revenue 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 (NREL 2009).

In addition to decoupling programs, Lost Revenue Adjustment Mechanisms (LRAMs), riders, and trackers 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 energy throughput and revenue weakens, allowing electricity service providers to recover fixed costs even though electricity consumption may decline due to the impact of energy efficiency programs.

There are 13 states, including the District of Columbia, that currently have a revenue decoupling mechanism in place (Figure 3.9), eight states with decoupling policies pending, and nine states with LRAMs. States that have enacted decoupling policies since 2008 include Hawaii, Idaho, Massachusetts, Nevada, Oregon, Vermont, and Wisconsin (IEE 2010a).

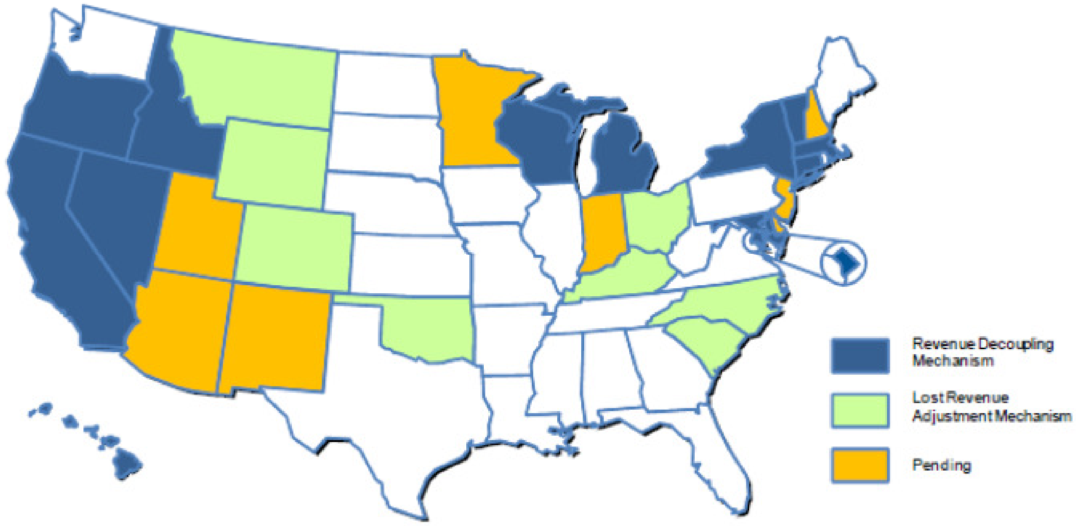


Figure 3.9. Status of States with Decoupling or Lost Revenue Adjustment Mechanisms (IEE 2010a)

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. Performance incentives for electricity service providers refer to regulatory standards enacted to compensate providers that invest in efficiency technologies and programs. Figure 3.10 demonstrates that 21 states now have a performance incentive in place with an additional 7 states having pending policies. Colorado, Hawaii, Kentucky, Michigan, New Mexico, New York, North Carolina, Ohio, Oklahoma, South Carolina, South Dakota, Texas, and Wisconsin have all approved incentives since 2008 (IEE 2010a). Due in part to the improvement in the regulatory climate, budgets for energy efficiency programs in the U.S. grew from $2.7 billion in 2007 to $4.4 billion in 2009 (IEE 2010b).

The markets established through new energy technologies have gained increasing recognition with private investors as venture capital firms have expanded their investments in smart grid technology providers. This interest has been spurred on by several investment drivers:

- high oil prices making energy delivery by electricity service providers more costly
- peak demand growing at a time when energy infrastructure is in need of updating and replacement
- shrinking capacity margins
- increasing recognition of clean and efficient technologies.

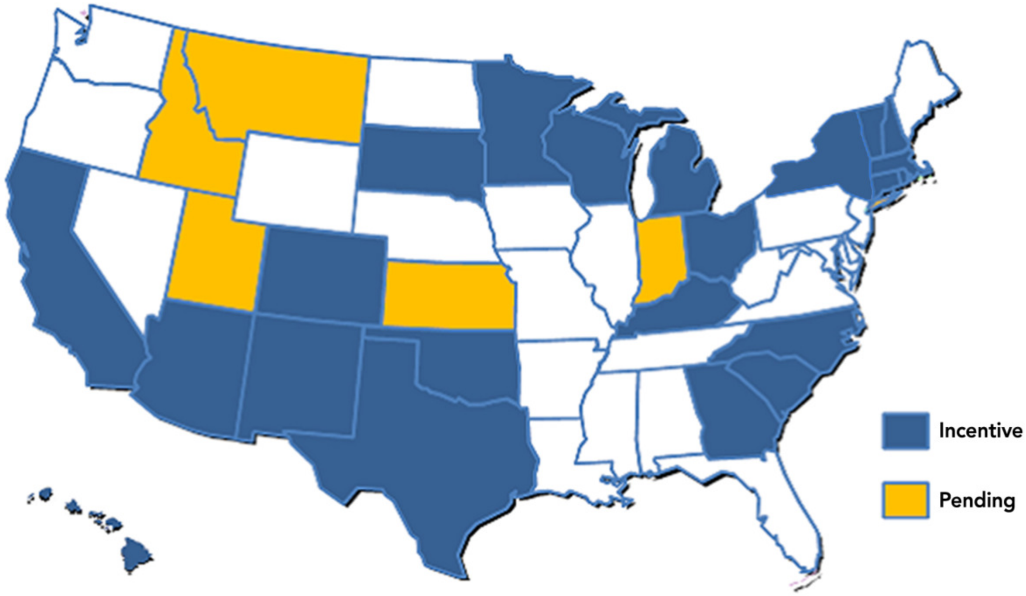


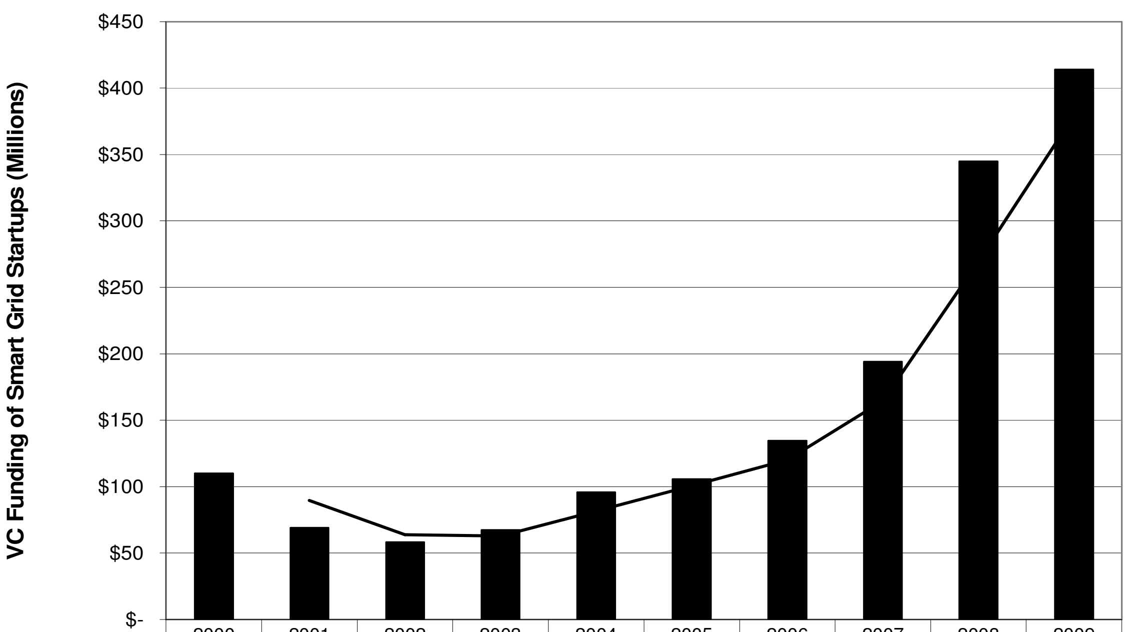
Figure 3.10. Improved Performance Incentive Programs (IEE 2010a)

These drivers suggest that in the future, new products, services, and markets will be required to address the growing demand for energy over the long term. As a result, investment in smart grid technologies has continued to gain traction. In 2009 alone, numerous significant venture capital deals were announced:

- SynapSense received $7 million for the development of wireless energy-efficiency solutions and data centers.
- Silver Spring, which is a wireless smart grid equipment and software developer, received $15 million.
- Tendril Networks 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 secured $2 million to develop hardware and software systems designed to monitor and manage energy usage and other commercial building activities.

The surge in private sector investment was validated with venture capital data for the smart grid market for 2000 through 2009 obtained from the Cleantech Group. 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 $414.0 million in 2009, representing a two-year growth rate of over 113 percent (Fan 2008, Cleantech Group 2010). While significant, smart grid venture capital investment represented only 7 percent of the total clean technology investment monitored by Cleantech in 2009. The largest sectors for clean technology venture capital investment in 2009 included solar ($1.2 billion), transportation ($1.1 billion), energy efficiency ($1.0 billion), and biofuels ($554 million). In total, the Cleantech Group identified smart grid venture capital deals totaling more than $1.6 billion during the 2000 through 2009 timeframe.

Data provided by the Cleantech Group were used to construct Figure 3.11. 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 through 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.



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
■ VC Funding	109.90	69.15	58.38	67.44	95.81	105.66	134.72	194.05	345.00	414.00

Figure 3.11. Venture Capital Funding of Smart Grid Startups (2002 through 2009)

Figure 3.12 breaks down venture-capital funding for the 2007 to 2010 time frame by the type of services provided for each smart grid company in the Cleantech Group database. From 2007 through 2010, more than 50 percent of the venture capital spending in the smart grid area went to metering companies (Figure 3.12). Home energy management companies received 20 percent of all venture capital spending and building energy management companies received 18 percent during the 2007 through 2010 timeframe (Neichin and Cheng 2010).

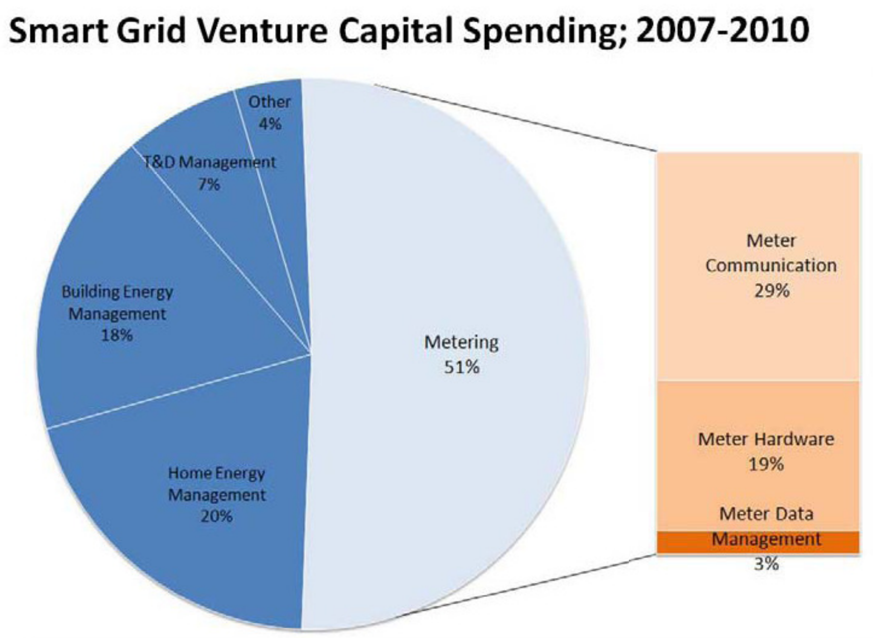


Figure 3.12. Venture Capital Spending by Company Type (2007 through 2010)

Advanced metering technology is a key facilitator of new markets because of its ability to record energy usage on very short time intervals [Metric 12–Advanced Meters]. AMI and other communicating technologies can provide the means to communicate real-time pricing data, grid conditions, and consumption information. More detailed data improves the flow of pricing information to consumers, improves accuracy of demand forecasts, and enhances the ability of the electricity service provider to respond to surges in demand. Further, the exchange of real-time prices and market data allows consumers to effectively monitor their energy consumption and respond to dynamic pricing tariffs. AMI penetration reached 7.95 million meters installed nationwide in 2009. 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 (FERC 2009b).

Venture capital is only one source of R&D funding for 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 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 (IEA 2010ARRA allocated $3.4 billion to smart grid matching grant programs, including $327 million to research, instrumentation, and laboratory infrastructure development (DOE 2009b). Although ARRA funding was a one-time stimulus package, DOE (2010b) released a congressional budget request for fiscal year (FY) 2011 in February 2010, designating $39.3 million for smart grid R&D. ARPA-E, which was initially funded through ARRA in 2009, will continue to be funded through the DOE in 2011. The National Science Foundation (NSF) has also allocated funds in the FY 2011 budget for smart grid projects. Divisions that will receive funding include the Directorate for Computer and Information Science Engineering, which budgeted $29.36 million for all R&D, the Directorate of Engineering, which allocated $120 million for a variety of projects, including smart grid development, and the Division of Antarctic Infrastructure and Logistics, which will receive $2 million to build AMI and monitor energy consumption at the McMurdo station (NSF 2010).

In addition to federal spending, contributions to smart grid R&D include many nonprofit organizations, products and service companies, electricity service providers and commissions. One such organization is EPRI (2010), which has allocated $15.6 million to R&D projects taking place in 2010. Projects include grid operations, planning, distribution, energy storage, demand response, distributed renewable generation and PHEV grid integration. In addition, the California Energy Commission (CEC)has appropriated $83.5 million to R&D annually as legislated through Senate Bill 1250 (CEC 2010).

R&D projects include demand response, renewable energy development and advanced grid technology research. Demand-response equipment also enables the design and function of new markets. From a system operations point of view, demand response is sometimes viewed as a form of additional capacity and is discussed in terms of MW. A 2008 FERC report estimated that the potential generation reduction due to such demand-response programs is approximately 41,000 MW per year. While the opportunity is significant, there is little standardized supporting infrastructure to communicate with grid-responsive demand-side equipment, nor is there significant demand for it yet since only approximately 8 percent of U.S. energy customers now have any form of time-based or incentive-based price structure (FERC 2008).

Microgrids represent another new smart grid-enabled market area [Metric 6–Load Served by Microgrids]. A microgrid is a distribution system with distributed energy sources, storage devices, and controllable loads that may generally operate connected to the main power grid but is capable of being operated as an island. Microgrids could 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 in which centralized generating systems are supplemented with small, more distributed production using smaller generating systems, such as small-scale combined heat and power (CHP), small-scale renewable energy sources and other distributed energy resources.

The cost of connecting and configuring smart devices and systems into the electricity grid remains an obstacle to the high volume penetration levels anticipated. For automation components to connect and work, alignment is needed in communication networks, information understanding, business processing, and business and regulatory policy (see Figure 3.13). This alignment results in interoperability and it is aided by integration methods and tools, as well as adherence to standards and agreements that cover all these aspects [Metric 19–Open Architecture/Standards]. Interoperability is a key element necessary to enable smart grid applications, and requires active collaboration from all stakeholder groups.

Under EISA, 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 (110 USC 1305).” In November 2009, NIST formed the SGIP and encouraged smart grid stakeholders from all organizations associated with electric power to establish this community and advance interoperability through goals, gap analysis, and prioritized efforts designed to address the challenges to integration (Widergren et al. 2010).

Following two stakeholder workshops, EPRI, which had been awarded a contract by NIST, produced a Report to NIST on the Smart Grid Interoperability Standards Roadmap. The report identified more than 80 current standards that might be applied or adapted to aid in meeting smart grid interoperability or cyber security goals. Further, it identified more than 70 standardization gaps and issues that require further attention (NIST 2010).

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 2010). The Smart Grid Interoperability Maturity Model (SG IMM) proposes three major categories that need to be aligned to achieve interoperability: technical, informational, and organizational. Figure 3.13 represents a simplified version of the SG IMM, 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.

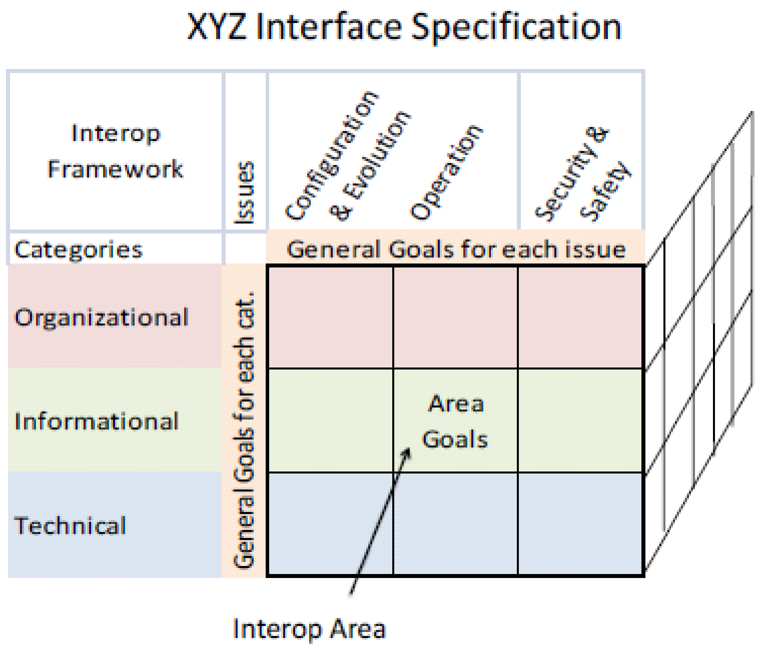


Figure 3.13. Interoperability Categories (Widergren et al. 2010)

3.4 Provides Power Quality for the Range of Needs

Customer requirements for PQ are not uniform across the residential, commercial and industrial sectors. PQ issues can include voltage sags, lightning strikes, flicker, and momentary interruptions. Customer needs for PQ range from those of data centers, which currently require on-site uninterruptible power supplies, to industrial plants, which need continuous power requiring dual distribution feeders and backup generation, to residential customers who are only occasionally irritated by flashing digital displays after a momentary interruption.

Related Metrics
5, 6*, 7, 9, 11, 17*, 21

Currently, the transmission grid and distribution systems are interconnected and can interact with each other. Examples of this would include an arc furnace or large motor causing lights to flicker on the same or different transmission lines or distribution segments. PQ problems at commercial customer facilities can affect nearby facilities on the same distribution feeder or particularly on the same distribution transformer. Current regulatory oversight of utilities focuses on power interruption, not PQ.

Smart grid implementations, along with new regulation, could allow service providers to provide varying grades of PQ. Higher-power-quality services could be provided based on location, such as via a particular distribution feeder, or at a “power quality park.” Controls would be necessary to monitor and counteract problems arising from switching surges, lightning strikes, line faults or harmonic sources nearby. Providing these options would require a supportive regulatory framework and an attractive product and service offering to interested customers. In many PQ situations, service providers offer premises-based PQ devices; these are usually placed at the service entrances and billed for on a monthly basis.

The options for enhancing PQ with a smart grid [Metric 17–Power Quality] cover a range of technologies and service provider program approaches, including

- PQ meters,
- system-wide PQ monitoring,
- demand-response programs,
- storage devices (e.g., batteries, flywheels, superconducting magnetic energy storage),
- inverter technologies to correct fluctuations in the quality of power from intermittent distributed renewable resources,
- new DG devices with the ability to provide premium power to sensitive loads,
- active control of voltage regulators, capacitor banks, and inverter-based DG and storage to manage voltage and volt-amps reactive (VARs),
- remote fault isolation,
- dynamic feeder reconfiguration, and
- microgrids.

Future technology gains could greatly increase PQ while reducing costs associated with interruptions and associated productivity losses. A loss of power or a fluctuation in power causes commercial and industrial users to lose valuable time and money. This section of the report focuses on PQ issues rather than power disruptions, which are covered in Section 3.6.

The Cost of Poor Power Quality

In the past, PQ incidents were often rather difficult to observe and diagnose due to their short durations. The increase in digital and power-sensitive loads has forced us to more narrowly define PQ. For example, ten years ago a voltage sag might be classified as a drop by 40 percent or more for 60 cycles, but now it may be a drop by 15 percent for five cycles (Kueck et al. 2004).

Cost estimates of power interruptions and outages vary. A study prepared by Primen, Inc. in 2002 concluded that PQ disturbances alone cost the U.S. economy $15 to 24 billion annually (McNulty and Howe 2002). In 2001, EPRI estimated power interruption and PQ cost at $119 billion per year (Primen 2001), and a 2004 study from Lawrence Berkeley National

Laboratory (LBNL) estimated the cost at $80 billion per year (Hamachi LaCommare and Eto 2004). A 2009 NETL study suggested that these costs are approximately $100 billion per year, and further projected that the share of load from sensitive electronics (microchips and automated manufacturing) will increase by 50 percent in the near future (NETL 2009). The range of costs for power interruptions can vary from $0.1 per kw in commercial businesses to $60+ per kw of demand in semiconductor foundries. Detailed cost estimates can be found in Table M.17.1 of Appendix A.

LBNL produced a report in 2009 that analyzed the results of 28 customer value-of-service-reliability studies conducted by ten U.S. electric utilities between 1989 and 2005. Table 3.6, which is not limited to momentary outages, summarizes the costs associated with types of PQ disturbances (NETL 2009).

Table 3.6. Estimated Average Electricity Customer Interruption Cost Based on U.S. 2008 Dollars by Customer Type and Duration

	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.					

Smart Grid Solutions to Power Quality Issues

Smart grid 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” (Uluski 2007). If operated properly, transmission and distribution automation systems can provide more reliable and cost-effective operation through increased responsiveness and system efficiency, all of which lead to improved PQ.

DOE’s 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 3 to 5 years. Substation automation projects (Irwin 2010) are estimated to number 671, affecting 5 percent of the total 12,466 T&D substations in the U.S. [Metric 11–T&D Automation].

Microgrids [Metric 6–Load Served by Microgrids] hold the promise of enhancing PQ and improving efficiency, when successfully implemented. A microgrid is an integrated distribution system with interconnected loads and distributed energy sources and storage devices, which operates connected to the main power grid but is capable of operating as an island; it could be as small as a city block or as large as a small city (Lasseter et al. 2002, Rahman 2008). Key distinctions between a microgrid and distributed generation are the ability of the microgrid to be islanded with coordinated control (Lasseter 2007). Table 3.7 shows federal funding commitments made to developing microgrids (DOE 2010c, SGIC 2010).

Grid responsive load [Metric 9–Grid-Responsive Non-Generating Demand-Side Equipment] measures the amount of load that can respond to signals (price or otherwise) and participate in system operations. Grid responsive load can be aggregated to participate in demand response programs.

Table 3.7. Federally Funded Micro Grid 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 right-of-way. Finally, it will install and operate a utility-scale diesel generator, batteries and related equipment, and components within the existing Borrego Springs substation (DOE 2010c).
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 (SGIC 2010).
Illinois Institute of Technology	IL	Chicago	The project received $7 million in DOE funds to develop an integrated microgrid system capable of full islanding (SGIC 2010)

Demand response was defined by the U.S. DOE in its September 2007 report to Congress (FERC 2007b):

> "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."

Examples of grid-responsive equipment, which could positively impact PQ issues, 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.

Various types of DG [Metric 7–Grid-Connected Distributed Generation] and energy-storage equipment are connected to the grid and can range from backup generators, microturbines, CHP systems, solar panels, wind turbines and a wide range of energy storage technologies that include batteries, compressed air storage systems, flywheels, and ultra-capacitors. Unlike large and centralized generators that provide most of the grid’s power, DG systems are noted for their smaller-scale local power generation (10 MVA or less), and they can be connected to primary and/or secondary distribution voltages (IEEE 2003).

Energy storage can improve PQ by storing energy during periods of low demand and discharging energy back into the system during peak periods. Thus, it can function as a generator with limited energy (during the discharging mode) and as a load (during the charging mode).

Energy storage systems have the ability to:

- integrate intermittent renewable energy technologies
- act as an uninterruptable power supply, which is the electricity system equivalent of providing ancillary services such as load following, regulation and spinning reserve
- defer upgrades to transmission and distribution infrastructure and provide an alternative to inflexible, “lumpy” additions to transmission and distribution capacity.

Of the projects funded by ARRA, there are 37 with a combined value of $637 million that combine smart grid and energy storage functionalities. Additionally, ARRA funding of $2.4 billion is directed toward aiding vehicle battery and component manufacturers [Metric 8–EVs and PHEVs]. 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. This could include, but not be limited to, storage at the distribution transformer level, also known as community energy storage. Vehicle-based battery systems offer an energy storage option that could provide the equivalent of an uninterruptable power supply to a home or neighborhood, thus increasing power reliability at the end-user level and improving PQ.

With advancement of energy storage systems, grid-connected renewable electricity generation [Metric 21] could also serve to enhance PQ and has climbed from a little over 2 percent of total grid-connected electricity generation in 2005 to over 3.5 percent in 2010 (Figure 3.14). 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-hours (GWh) in 2005 to more than 70 GWh in 2010 (EIA 2010e).

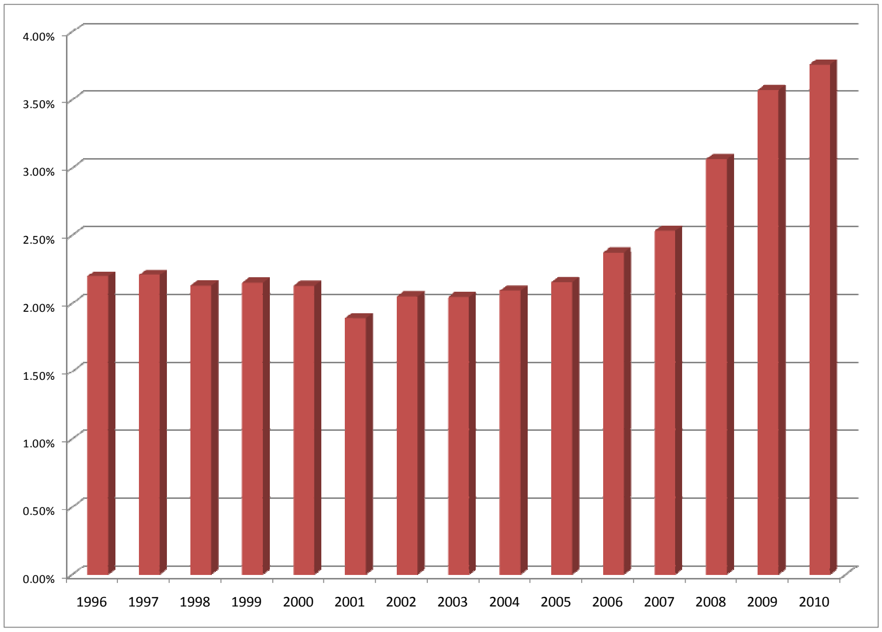


Figure 3.14. Trends in Renewables as a Percent of Total Net Generation (EIA 2010e)[3]

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 penetration of intermittent renewables is indicated by net wind and solar summer capacity as a percent of total summer-peak capacity. Currently, nationwide intermittent generation comprises approximately 2.5 percent of total capacity (EIA 2010e). Nationwide wind capacity is forecast to more than double by 2035, reaching 5.5 percent (EIA 2010d).

3.5 Optimizing Asset Utilization & Operating Efficiency

The premises of the smart grid concept are lower operations costs, lower maintenance costs and greater flexibility of operational control than the current grid system exhibits. This operational efficiency and improved asset utilization will be driven by advanced communication and information technologies. Better monitoring and control technologies reduce the need for additional generation plants and towers or transmission lines, and thereby reduce the need for increased generation through demand response measures and energy efficiency.

This section reports on smart grid improvements in asset utilization and operating efficiency in bulk generation, T&D delivery infrastructure, and distributed energy resources in the electricity system. It concludes with an overall view of system efficiency.

[3] The percent of net generation for 2010 is based on the first 3 months of net generation data for 2010.

Related Metrics
2, 3, 5, 7, 11*, 13, 14*, 15*, 16*

3.5.1 Bulk Generation

The United States crept closer to its generation limits for at least the ten years preceding 2000 according to NERC data, but it sharply 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. The trends in the data can be observed in Figure 3.15, which points out the maximum and minimum capacity factors and years for each of the three data sets. A capacity factor [Metric 14] 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 during that interval. Capacity factors have declined from the previous SGSR because of the economic downturn. Load dropped as business activity declined, leaving a fairly constant generation resource to serve a smaller load, thus reducing the capacity factor. A rising capacity factor can be viewed as a positive measure from the standpoint of asset utilization and the smart grid could enable higher capacity factors without a reduction in grid reliability.

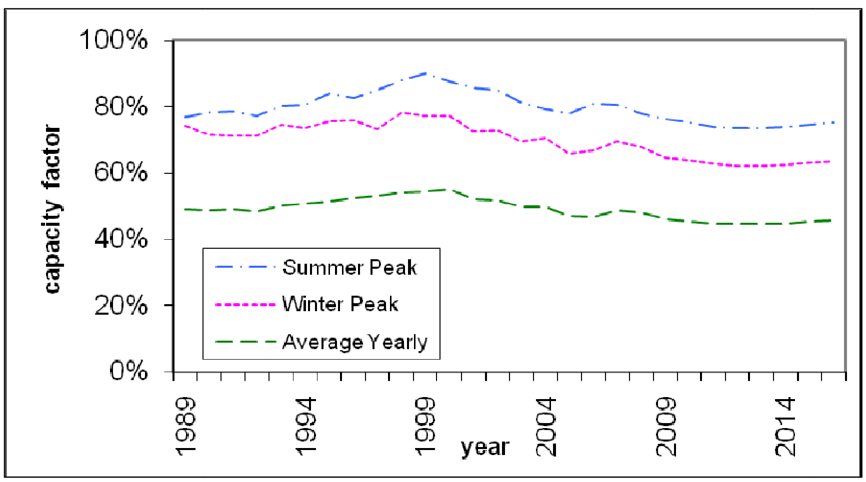


Figure 3.15. Measured and Predicted Peak Summer, Peak Winter, and Yearly Average Generation Capacity Factors in the U.S. (NERC 2009a)

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 efficiency rates since the 1950s suggests the limitation of the Carnot efficiency for large plants, while the increase in gas efficiency shows the improvement from gas turbines, mostly because of greater use of combined cycle power plants. Figure 3.16 shows how the efficiency of generators that use fossil fuels in the United States has improved over time. The trends show a relatively low starting efficiency, with rapid increases for most fuels.

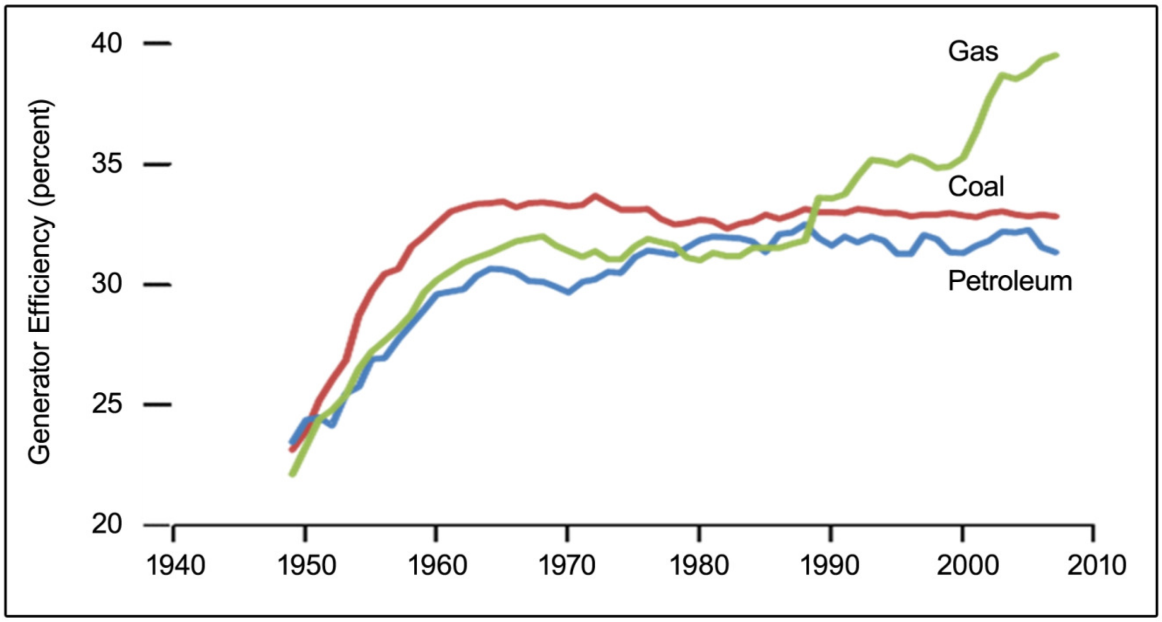


Figure 3.16. Generation Efficiency for Various Fossil Fuel Sources over Time (EIA 2007b)

The capacity factor for the United States has remained nearly unchanged from 2006 to 2008, making only a marginal improvement. Table 3.8 summarizes peak, generation, and capacity data and the resulting annual average national capacity factor measurements for 2006 and 2008, the most recent years for which data are available. On average, a little less than half of the nation's generation capacity is now used, but more than 80 percent of the nation's total generation capacity is used during summer peaks. Smart grid techniques should be able to increase asset utilization, thus increasing overall capacity factors.

Table 3.8. Measured and Projected Peak Demands and Generation Capacities for Recent Years in the U.S. (NERC 2009a) and Calculated Average Capacity Factors

	2006	2008
Summer peak demand (MW)	789,475	755,614
Summer generation capacity (MW)	954,697	997,911
Capacity factor for Metric 14a, peak summer (%)	82.69	75.71
Winter peak demand (MW)	640,981	644,869
Winter generation capacity (MW)	983,371	976,258
Capacity factor for Metric 14a, peak winter (%)	65.18	66.05
Yearly energy consumed by load (GWh)	3,911,914	3,989,058

Capacity factor for Metric 14a, average (%)*	46.08	46.13
*The average of the NERC (2006 and 2008) summer and winter capacities was used for this calculation.		

3.5.2 Delivery Infrastructure

Data from electricity operators across the nation show a clear trend of increasing T&D automation [Metric 11–T&D Automation] and increasing investment in these systems. Key drivers for the increase in investment include operational efficiency and reliability improvements that 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 the T&D operation, operational changes can be introduced to operate the system closer to capacity and stability constraints. T&D automation encompasses a large set of technologies, including 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.

Results of interviews undertaken for the 2010 SGSR report indicate that:

- 47.7 percent of the total substations owned by respondents were automated.
- 78.2 percent of the total substations owned by respondents had outage detection.
- 82.1 percent of total customers had circuits with outage detection.

According to a multi-year study of electric power utility capital expenditure budgets conducted by Newton Evans, planned investment in T&D infrastructure grew in 2010 relative to 2008 and 2009 levels. More system operators were planning increases in T&D automation investments (41to 43 percent) than those decreasing future expenditures (5 to 11 percent). Smart grid initiatives were cited as being more important factors in stimulating increased investments than either regulatory mandates or government stimulus programs, as seen in Table 3.9.

Table 3.9. Rationale for Change in Investment

Year	Regulatory Mandates	Smart Grid Initiatives	Government Stimulus
2010	45%	62%	41%
2011	42%	64%	41%

DOE has announced that the SGIG program will fund the installation of 877 PMUs for near-nationwide grid coverage by wide area measurement systems (WAMS) technology. This number is over five times the current installed number (166) of networked PMUs (Overholt 2010). Data sharing from the field and between control centers and reliability coordination centers improves the true operational view of the system without which engineering buffers are developed that allow for inaccuracy or unpredictable situations. Advanced measuring devices such as synchrophasors help improve the situational awareness and reduce the engineering margin [Metric 13–Advanced System Measurement].

Dynamic line ratings (DLR) [Metric 16], also referred to as real-time transmission-line ratings, are a well-proven tool for enhancing the capacity and reliability of our electrical transmission system. Modern dynamic line-rating systems can be installed at a fraction of the cost of other traditional transmission-line enhancement approaches. One of the primary limiting factors for transmission lines is temperature. When a transmission line current increases, the conductor heats up, 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).

A dynamic line-rating system can increase line transmission capacity by 10 to 15 percent by feeding real-time data into the normal, emergency, and transient ratings of a line, which about 95 to 98 percent of the time results in a less-conservative, higher-capacity rating of the line (Seppa 2005). The 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. In a particularly interesting twist, transmission of wind energy might become enhanced by dynamic line ratings due to the cooling effect of wind (Oreschnick 2007).

The number of locations where dynamic line rating equipment is installed is small, monitoring only a fraction of the nation’s transmission lines. There are a few pilot projects intended to determine the feasibility and reliability of dynamic line rating equipment operating in real time. A smart grid demonstration project being conducted by the Oncor Electric Delivery Company LLC is using 45 load-cell tension-monitoring units and eight master locations to demonstrate that DLR can relieve congestion and transmission constraints, provide operational knowledge, make sure that safety-code clearances are not broken, and quantify/identify any operational limits. The New York Power Authority is conducting a demonstration project that evaluates instrumentation and dynamic thermal ratings for overhead transmission lines. EPRI is providing their Dynamic Thermal Circuit Rating (DTCR) software, which provides dynamic ratings based on actual load and weather conditions. Real-time data will be provided using temperature monitors, video sagometers and tension monitoring equipment (Mayadas-Dering et al. 2009).

The interviews of electricity service providers conducted for the 2010 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.

3.5.3 Distributed Energy Resources

Smart grid applications, such as demand response [Metric 5–Load Participation Based on Grid Conditions] and grid-connected DG [Metric 7], should also improve grid operating efficiency by controlling load and adding localized resources when required. In order for this to occur, favorable DG interconnection standards are needed [Metric 3–Distributed Resource Interconnection Policy]. According to a 2008 FERC Survey, only about 8 percent of customers have a time-based rate or are involved in some form of a demand response program. In addition, the number of service providers offering load management and demand response programs is small, with direct load control (DLC) and interruptible/curtailable tariffs listed as the most common incentive-based demand response programs (FERC 2008) (see Table 3.10).

Table 3.10. Entities Offering Load-Management and Demand-Response Programs (FERC 2008)

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

Asset optimization and operating efficiency go hand in hand, especially in serving the provider's most expensive loads, i.e., peak load. There is potential to use a combination of cost-effective resources to meet system needs for summer-peak shaving, and demand response programs could encourage consumers to be active in dynamic pricing programs. For example electricity service providers could send price signals based on market conditions, and in turn, end users would respond by pre-cooling buildings when energy prices are lower. As electricity prices rise, because demand is increasing, thermostats could be set to higher or lower temperatures to reduce load (this option is cheaper than turning on backup generation). Lastly, if demand response and load control resources are exhausted, then prices rise further and DG would be turned on to meet peak demand. The above scenario is essentially what the California Independent System Operator (CAISO) does with operation of its demand response program utilizing the Open ADR standard (PIER Demand Response Research Center, 2010).

3.5.4 Overall System Efficiency

Once the electricity has been generated, the delivery process is much more efficient, though the total quantity delivered means that even a small percentage loss represents a significant dollar amount [Metric 15–Generation and T&D Efficiencies]. The overall efficiency of the grid is depicted in a diagram from EIA (2009) that shows the energy losses associated with each piece of the overall process of generating and delivering electricity (see Figure 3.17). Generation efficiency is measured in terms of heat rate (Btu/kWh), 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 3.18. Note that although the energy lost to transmission and distribution is a small fraction of the Carnot-cycle losses, they are not small in absolute terms, and are worth addressing.

Total T&D losses were 245.9 billion kilowatt-hours in 2008. EIA data show a total of about 4,000 billion kWh for the year, resulting in a 7.5 percent loss (see Figure 3.19). While the efficiency number seems strong, the energy loss is equivalent to continuous generation of 28 GW, approximately the level produced by 29 large power stations.

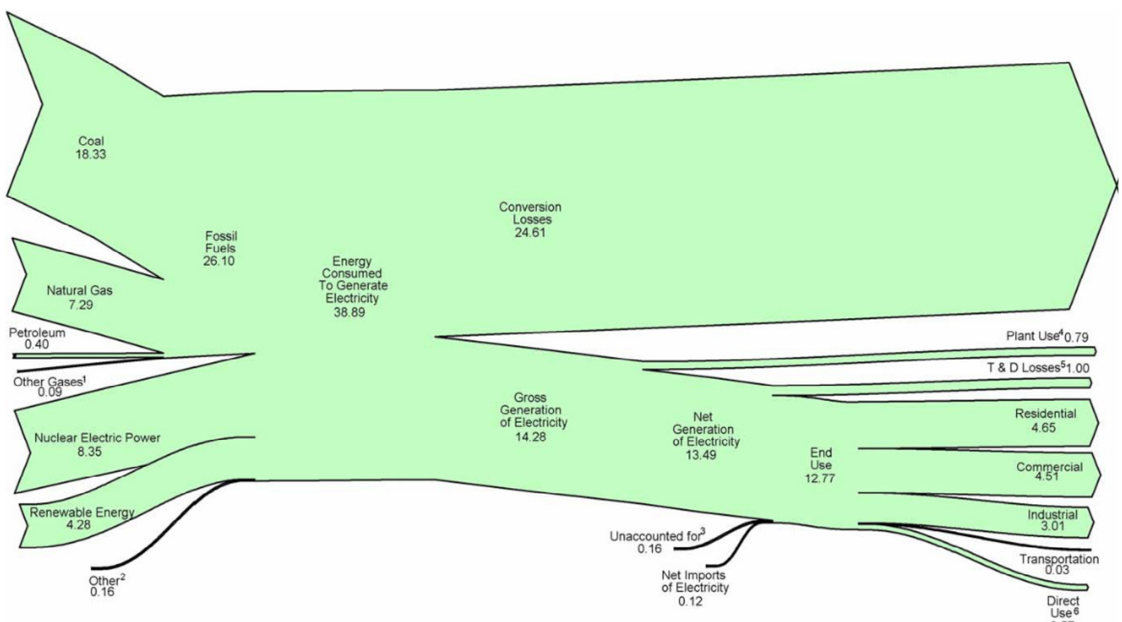


Figure 3.17. Electricity Flow Diagram 2009 (Quadrillion Btu) (EIA 2009)

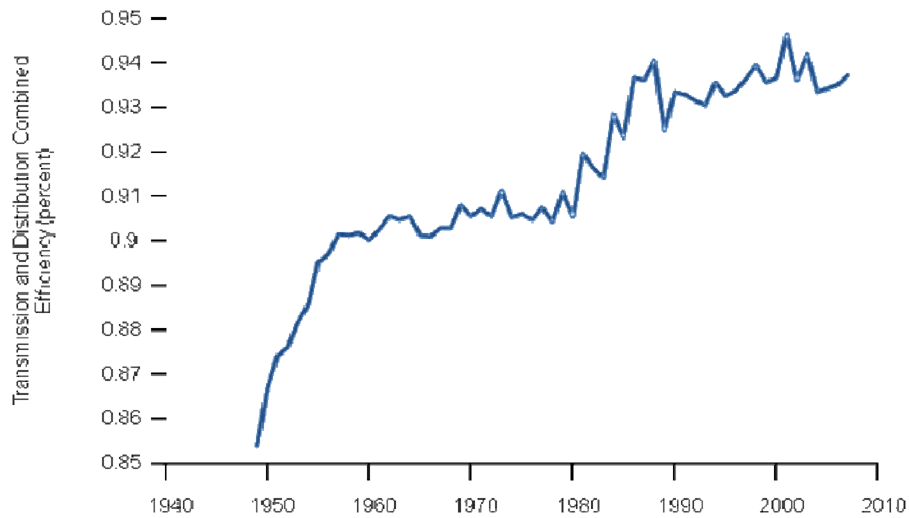


Figure 3.18. Combined Transmission and Distribution Efficiency over Time (EIA 2009)

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. DOE is also working on related technology and recently awarded a $3.7 million grant to Cree, a North Carolina-based company that is developing high-voltage silicon carbide transistors for power management in electrical substations.

3.6 Operates Resiliently to Disturbances, Attacks, & Natural Disasters

Resilience refers to the ability of a system to respond to disturbances such that the rest of the system is restored to or is able to maintain normal operations. These "self-healing" responses enable reduced interruption of service to consumers and help service providers to better control the delivery infrastructure. Whether the disturbances are caused by an accident, natural disaster or terrorist attack, a smart grid responds appropriately to maintain the grid's ability to function. A terrorist attack could be either from physical attacks upon the infrastructure or from cyber-attacks on the communications system either through internet or other signaling devices. Thus, a smart grid requires a balanced approach across all of its elements at all stages to make sure that the entire system is protected, integrated and operating synchronously.

Operational resilience is arguably the most important characteristic of a smart grid from a national security point of view. Resilience cuts across all the other characteristics of a smart grid, regardless of adverse conditions or unforeseen events. Unlike some of the other metrics, resilience and security are embedded in operational philosophies, processes, rules, and vigilance. While it must be pervasive throughout the system, resilience is a less tangible quality. Resilience requires an ability to understand the system's vulnerabilities, to quantify its risks, and to adjust approaches, operational techniques and postures through repeated evaluations. Most of the metrics measuring progress of a smart grid's advancement contribute to an understanding of the progress for this characteristic.

The primary metrics of progress for this attribute include real-time data sharing [Metric 2], grid-responsive non-generating demand-side equipment [Metric 9], T&D system reliability [Metric 10], advanced sensors [Metric 13] and cyber security [Metric 18]. A number of other metrics describe the system's ability to operate resiliently to disturbances, attacks, & natural disasters.

Related Metrics
1, 2*, 5, 6, 7, 8, 9*, 10*, 11, 12, 13*, 16, 18*

Given the great numbers of automation components interacting with a smart grid, an important operational facet for the future smart grid is distributed decision making. That is, equipment and smart grid subsystems need to share actionable information [Metric 2–Real-time System Operations Data Sharing] so that local decision making not only serves local self-interest, but collaboratively supports the overall health of the system. As individual components of the system fail, including processing and communications components, the remaining connected components have the ability to adapt and reconfigure themselves to best achieve their objectives.

Operational resilience has three basic descriptive properties: 1) ability to adapt, expand, conform, or contort when force is applied, 2) ability to perform satisfactorily or minimally while the force is in effect, and 3) ability to return to an appropriate expected state once the force stops or is rendered unproductive (Caralli 2006).

The state of smart grid deployment relevant to these properties is discussed in the following section according to the major metric areas described in Section 2.1.

3.6.1 Area, Regional, National Coordination

At the transmission system level, area control centers and regional reliability coordination centers have been exchanging system status information for many years now. These systems are being continually upgraded to share more information including SCADA data, state estimation results, and market data. The communication links between these systems now cover the country and an increasing amount of information is being exchanged with distribution-level systems.

A recent survey by Newton-Evans Research Company (2010) 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 (Newton-Evans 2010). Utilities were asked to report the level of EMS/SCADA/DMS systems in place, and specify the type of system. Results from the 2010 survey are represented in Figure 3.19.

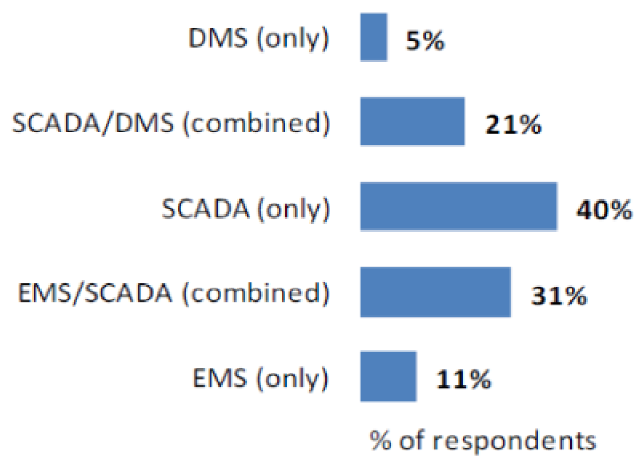


Figure 3.19. Current Installations of EMS/SCADA/DMS Systems by Type (Newton-Evans 2010)

PMU technologies provide data necessary to measure phasor information in real time. 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. There is no single authority keeping track of the deployment of PMUs. Therefore, the trends and projections given here were derived from several sources. Projections of the number of PMUs required to adequately monitor the grid vary from 500 to 1,300 PMUs based upon work by a NERC (2007) technical committee and a study completed by Northeastern University, respectively (Galvan et al. 2008).

The number of installed and networked PMUs has been increasing steadily in the past few years. The North American SynchroPhasor Initiative (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 significant increase in networked PMUs by 2014, with networked PMUs reaching 1,043 (Overholt 2010). Figure 3.20 illustrates the growth of networked PMUs between 2009 and 2014.

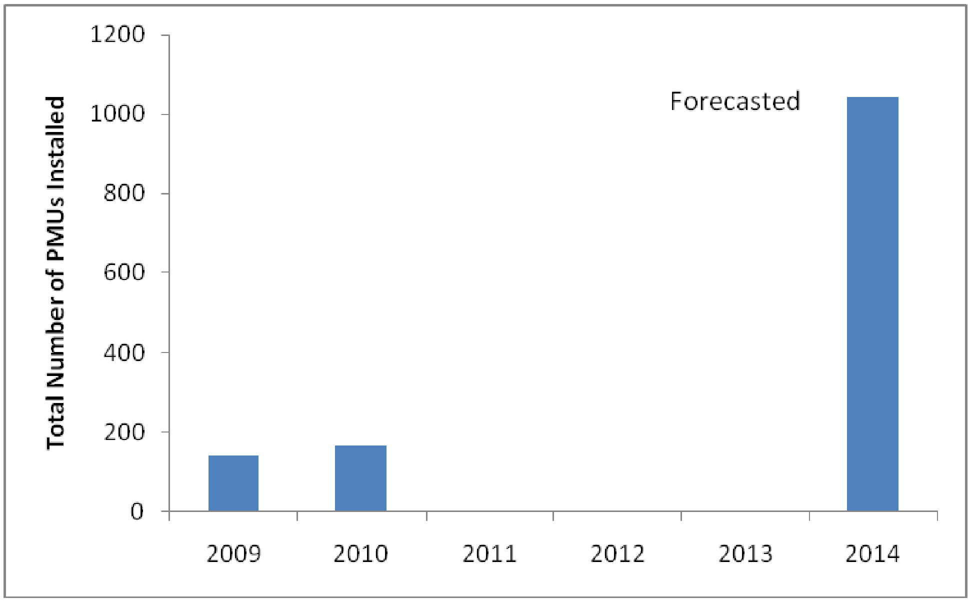


Figure 3.20. Number of PMUs Installed

A transformational aspect of a smart grid is its ability to incorporate DER, and particularly demand-side resources, into system operations. The ability of these resources to respond to local area, regional, and national conditions contributes to economic efficiency and system reliability. Market-based approaches encourage customers to use these and other system resources to adapt to changing system conditions. The scalability and financial incentives tied to such an approach support adaptation of the system to impending threats, disturbances, and attacks. In particular, CPP and RTP programs provide a mechanism for system operators and reliability coordinators to engage these resources to enhance operational resilience.

3.6.2 DER Response Metrics

A smart grid provides the flexibility to adapt to a changing mix of demand-side resources, including changeable load, dispatchable DG and storage, and variable-output local generation such as wind and solar. Demand-response resources can help alleviate generating capacity constraints or support electrically energized islands to mitigate the effects of events such as a disturbance, attack, or natural disaster. In addition, these resources can improve response times for post-interruption reconstruction.

Approximately 8 percent of customers have a time-based rate or are involved in some form of demand-response program [Metric 5–Load Participation Based on Grid Conditions], according to a 2008 FERC Survey. DLC and interruptible/curtailable tariffs are the most frequently listed demand response programs offered by electric service providers. However, the number of organizations offering such a program is low. FERC estimates that in 2009, peak demand reduction from demand response programs in RTO and ISO wholesale markets amounted to 37 GW (FERC 2009b).

Distributed generation capacity [Metric 7–Grid-Connected Distributed Generation] continues to be a small part of total power generation even though it has been steadily increasing over the years. Total DG capacity reached 5,423 MW in 2004 and grew to 12,863 MW in 2008, or 1.7 percent of non-coincident summer peak (EIA 2010a). Wind and other renewable energy sources grew significantly between 2004 and 2008, increasing by 1,051 percent, but that only represents 0.16 percent of total available generating capacity, 0.21 percent of summer peak capacity, and 0.24 percent of winter peak (EIA 2010c). Intermittent renewable-energy resources such as wind may not be effective resource to meet peak-demand, although solar has the potential to be more coincident with summer peak-demand periods.

Other distributed energy resources are just now emerging. These include microgrids [Metric 6–Load Served by Microgrids], which are designed to operate in both islanded and grid-connected modes, and EVs, including PHEVs [Metric 8]. Microgrids were 0.08 percent of net summer capacity in 2008 (EIA 2010a). EVs and PHEVs are a very small percentage of the market presently and they do not currently contribute energy back into the grid.

In addition, non-generating demand-side equipment that responds to grid conditions and pricing will also provide demand response [Metric 9–Grid-Responsive Non-Generating Demand-Side Equipment]. The products that have emerged and continue to evolve in this category either directly monitor or receive communicated recommendations from system operators. The 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. Smart grid-responsive appliances remain in their commercialization infancy. However, 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. For example, Austin Energy is presently evaluating the performance of 70,000 installed smart thermostats as part of its broader Pecan Street Project (FERC 2009b).

3.6.3 Delivery Infrastructure Metrics

Transmission and distribution substation automation projects and efforts to deploy advanced measurement equipment for applications such as wide-area situational awareness and dynamic line ratings are helping to improve the ability to respond resiliently and adapt to system events.

The general operating approach for using SCADA technologies, remote sensors and monitors, switches and controllers with embedded intelligence, digital relays, and a large number of other technologies 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” (Uluski 2007). If operated properly, transmission and distribution automation systems can provide more reliable and cost-effective operation through increased responsiveness and system efficiency.

Two recent studies by LBNL on the cost of T&D reliability incidents provide insight into the changing reliability of the grid. In 2004, electricity grid customers experienced 106 minutes of interruption (SAIFI), 1.2 interruptions (SAIDI), 4.3 momentary interruptions (MAIFI), and 88 minutes of outage per incident (Customer Average Interruption Duration Index, CAIDI). By 2006 these numbers had increased significantly with 244 minutes of interruptions (130 percent increase), 1.49 interruptions (24 percent increase), the number of momentary outages increasing to 6.55 (51 percent increase) and the average outage almost doubling to 164 minutes (Table 3.11).

Table 3.11. Regional Statistics on SAIDI, SAIFI and MAIFI 2006

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
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

Due primarily to slumping commercial and industrial energy demand resulting from the recent economic recession, forecasted peak electricity demand in NERC's 2010 Long Term Reliability Assessment was lowered 4.1 percent since the 2009 forecast, and 7.8 percent since before the recession began (NERC 2010c). Presently, NERC forecasts an annual growth rate of 1.34 percent between 2010 and 2019, resulting in peak (summer) demand rising from 772 GW to 870 GW (NERC 2010c).

Planning reserve margins demonstrate the forecast difference between peak electricity demand and capacity. Figure 3.21 illustrates the forecasted reserve margins from 2009 to 2018. The rise in the near term reflects the current decrease in overall electricity demand. Prospective systems are those planned or under construction, while deliverable systems represent those already online. As the US economy recovers and demand rises, reserve margins are forecast to decrease. Although reserve margins presented in this aggregated figure are not forecasted to fall below the 15 percent NERC reference level, regional projections vary significantly.

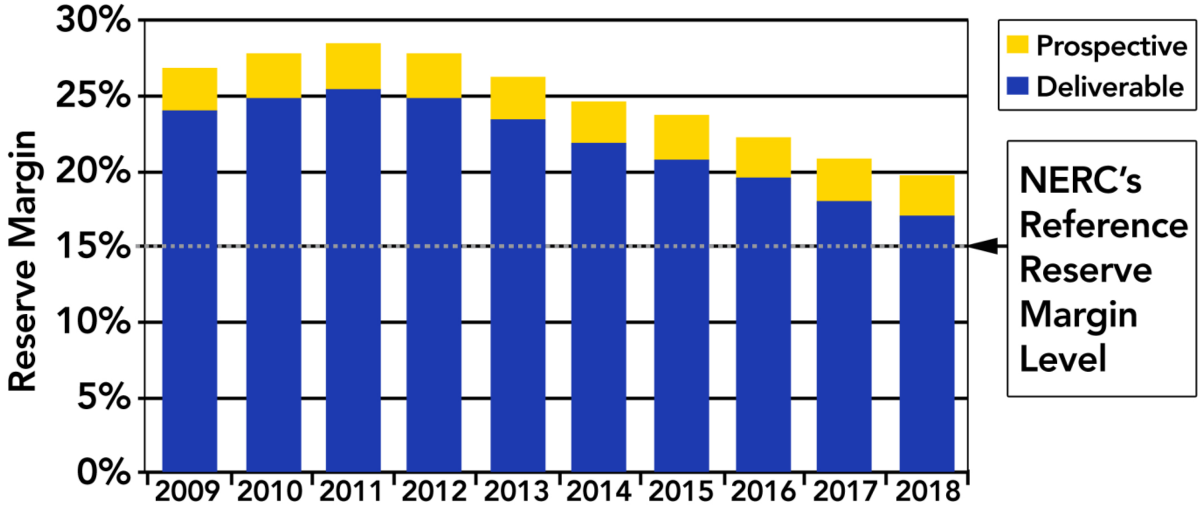


Figure 3.21. US Summer Peak Reserve Margin Forecast (NERC 2010d)

Deployments of T&D automation equipment and AMI indicate that distribution and transmission providers are taking steps to improve declining margins. Data from electricity operators across the nation show a clear trend of increasing T&D automation [Metric 11] through 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 the T&D operation, operational changes can be introduced to operate the system closer to capacity and stability limits. Recent research shows that while

84 percent of electricity companies had substation automation and integration plans underway in 2005, and about 70 percent of these companies had deployed SCADA systems to substations, the penetration of feeder automation is still limited to about 20 percent (McDonnell 2006, Moore and McDonnell 2007).

The capabilities of advanced meters will increase the accuracy of data for forecasts of price and demand as well as provide the grid a better ability to respond to blackouts and brownouts. With AMI, the grid can be more resilient. FERC forecasts a significant growth in AMI deployment [Metric 12–Advanced Meters]. The number of smart meters grew from approximately 0.9 million in 2006 to 6.7 million meters in 2008, 7.95 million in 2009 (FERC 2009b) and 16 million in 2010 (Neichin and Cheng 2010, King 2010), as represented in Figure 3.22.

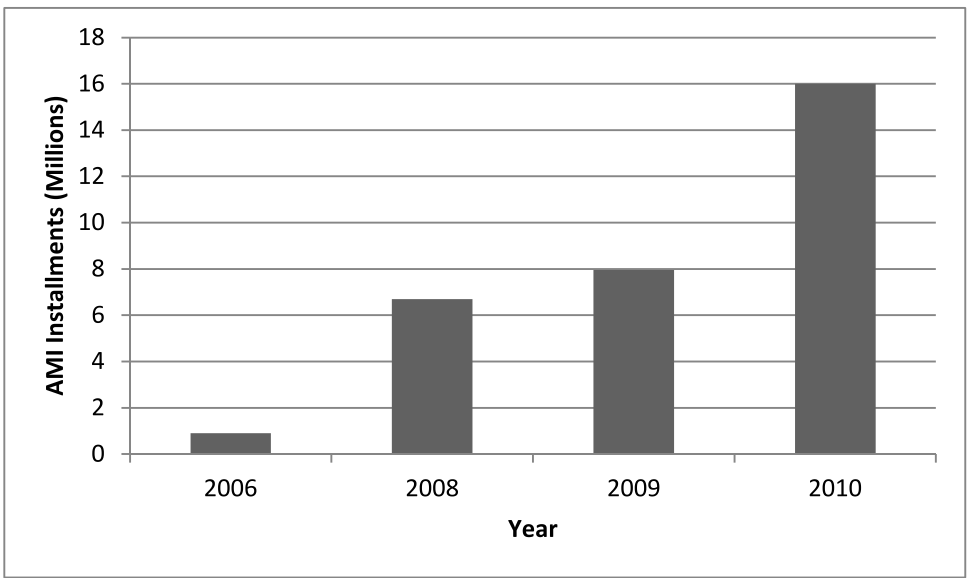


Figure 3.22. AMI Market Activity Growth

Federal grant awards for AMI implementation under ARRA total $812.6 million to date (DOE 2010a). States with the most significant AMI investment under ARRA include Texas, Maryland, Maine and Arizona, but projects are being undertaken by numerous electricity service providers in 19 states, with additional laws or policies passed in Hawaii, Massachusetts and Pennsylvania (FERC 2009b). Finally, since 2009, AMI pilots or full-deployment programs have been announced by 26 utilities in 19 states (FERC 2009b).

DLRs [Metric 16] enhance the understanding of real-time transmission line capacity. 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. One study found that 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 98 percent of the time and increasing capacity by 10 to 15 percent (Seppa 2005). Another study conducted by San Diego Gas & Electric found that monitored transmission lines had 40 to 80 percent more capacity than the static measurement of the line. These findings suggest that technologies such as DLR systems could be adopted to address capacity shortcomings if growth projections for transmission lines are not realized. Although DLRs are an important smart grid technology, there is no publicly available nationwide data on them at this time.

3.6.4 Secure Information Networks

The interconnected North American grid is arguably the world's largest and most complex machine. It has an enviable record of reliability through the application of numerous technological and operational efficiencies, and strong regulatory oversight. The grid's complexity and interconnected nature, however, 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.

The security challenges, including cyber security, resulting from the interconnected nature of the communication systems that support regional and interregional grid control and the mix of newer systems with older legacy systems constitute a significant hurdle to overcome. However, increased automation and intelligence in the field provided through microcontrollers and sensors will enable enhanced monitoring capabilities in field equipment installed in substations, within the distribution network, and even in customer's homes and businesses. All of these items, while posing security challenges, lead to significantly increased control capability and vastly increased flexibility and functionality.

Steady progress has been made on the development of cyber standards, their implementation and enforcement. The NERC CIP standards establish minimum requirements for cyber security programs protecting electricity control and transmission functions. In early 2008, FERC directed NERC to tighten the standards even further to provide for external oversight of classification of critical cyber assets and removal of language allowing variable implementation of the standards. Version 3 revisions await FERC approval (NERC 2009c) while Version 4 of the standards was being reviewed by the drafting team after receiving comments during the informal comment period (NERC 2008).

The (Revised) Implementation Plan for Cyber Security Standards CIP-002-1 through CIP-009-1 provides the implementation schedule for standards (Table 3.12) (NERC 2009d). CIP 002-4 has now become CIP 010-1, and CIP-003-4 through CIP-009-4 were consolidated into CIP-011-1 (Table 3.13) (NERC 2008).

Table 3.12. Summary of the NERC Critical Infrastructure Protection Standards CIP 002-009 (NERC 2010a)

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
*bulk electricity system (BES)	

Table 3.13. Summary of the NERC Critical Infrastructure Protection Standards CIP 010-011 (Emerging) (NERC 2008)

NERC Standard	Subject Area
CIP -010	BES Cyber System Categorization
CIP -011	BES Cyber System Protection BES Cyber System Categorization

The implementation schedule identifies when entities must:

- begin work to become compliant with a requirement,
- be substantially compliant with a requirement,
- be compliant with a requirement, and
- be auditably compliant with a requirement.

The implementation schedule requires all BAs, TOs, and RCs to be auditably compliant with NERC's Urgent Action Cyber Security Standard 1200 (UA 1200) by December 2010. There were different dates for each entity based upon their individual characteristics, but all types had to be auditably compliant by the end of 2010.

Enforcement of the standards has identified a lack of compliance and therefore violations. Identified violations are being reported according 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 3.23). As violations are found, they increase past values based on the date the violation was deemed to occur. Thus, the enforcement of standards and the subsequent corrections will over time lead to fewer and fewer violations as companies take steps to come into compliance.

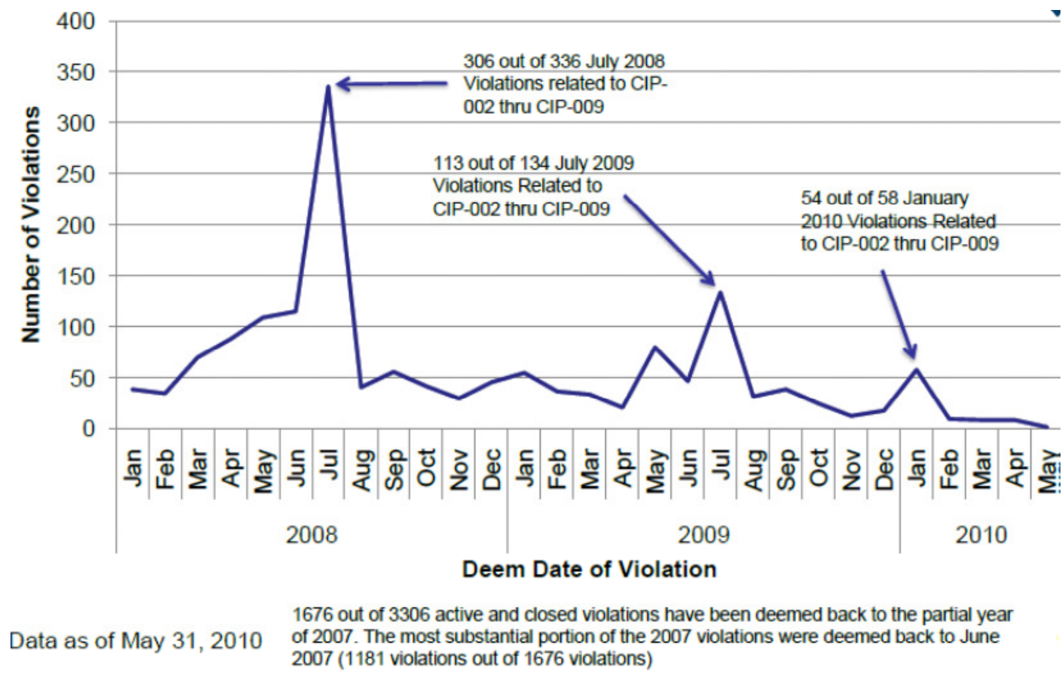


Figure 3.23. Deemed Date Trend for Active and Closed Violations (NERC 2010b)

Additionally, the interviews of 20 electricity service providers (Appendix B) included a question about specific security measures that utilities are implementing. The results are shown in Table 3.14.

Table 3.14. 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	50.0%
c. Encrypted communications	66.7%
d. Firewalls	91.7%
e. Others	12.5%

4.0 Challenges to Deployment

Significant challenges still exist for bringing the smart grid concept to fruition. Foremost among these challenges is the value proposition and the capital required to purchase the new technologies envisioned for communicating information between end users, electricity service providers, and distribution and transmission providers. Although progress has been made in the purchase and installation of PMUs and AMI deployments, estimates for advanced metering capital still range up to $40 billion despite the billions of dollars provided for smart grid funding in ARRA (Faruqui and Sergici 2009). With ARRA investments made in PMUs, the grid will be approaching the target level of PMUs anticipated to adequately monitor the grid (Overholt 2010).

Other areas of the grid including transmission, distribution, and software requirements will also require capital investment to update the grid. Entrepreneurs who can find the appropriate value propositions could lessen these significant capital requirements. However, with the rapid changes in technology, energy mixes, and energy policy, the path to a smarter grid system provides a degree of uncertainty that may not clearly signal large returns on capital for investors. Yet, if legislators and regulators try to legislate or regulate the smart grid's development in order to provide certainty to investors, they could inhibit technology innovations that might provide a more flexible and transparent energy market. Nevertheless, allowing the grid to develop in a free market environment without some guidance could put the energy grid and national interests at risk. For example, a failure to find a balance between regulation and the free market was demonstrated in the Pacific Northwest in the spring of 2011 when wind farm operators were turned off the grid. Too much electricity was generated for transmission equipment to accommodate and demand from electricity markets to consume because of the convergence of spring winds and large melting snow packs increasing hydro and wind electricity generation. In this case, there was an inability to address what happens when too much power enters the grid, leading to questions such as who must shut down when it occurs and who is responsible for ensuring the required distribution capacity is available to meet peak supply. Thus, the challenge is to balance enabling innovation while at the same time providing some certainty to the markets.

Technical progress is being made in the area of reliability and cyber standards that will protect the grid from major failures like the 2003 blackout of the Northeast but further progress is still needed. Significant progress has yet to be made in handling intermittent generation or valuing storage technologies and making them cost effective. Storage is one approach that could smooth generation from renewable resources such as wind and solar. Studies indicate that when variable renewable resources reach 20 percent penetration, they will be difficult and expensive to manage (Pratt et al. 2010). The software and hardware required to allow this integration are making significant progress, but the integration of these programs is still in the demonstration stage. Lastly, regulations are required to update reliability standards, encourage interoperability, establish favorable interconnection standards, and enable investment recovery for justified smart grid investments. These and other challenges are discussed in the following sections.

4.1 Technical Challenges

There are a number of technical challenges facing the smart grid associated with implementing demand response, monitoring and communicating loads and prices, and developing the standards required to ease the integration of these resources as participants in system operations. Among these challenges is the definition of the interoperability requirements that allow both sides of the meter to communicate with one another and to adjust consumption patterns based on real-time pricing, as well as the development of computer hardware and software, and communications infrastructure to handle dynamic pricing and AMI, developing appropriate interconnection standards to implement intermittent renewable energy resources, and standardization of communication protocols for demand-side management appliances. Lastly, more standardized codes, requirements and reporting of T&D reliability are needed (FERC 2007a).

Although AMI deployment has increased since 2008, there is still a lack of smart-meter infrastructure and a lack of interoperability and open standards (Kaplan 2009). In addition, the data infrastructure improvements required to collect and support the necessary data accessibility need to be developed. National smart-meter readings are estimated to require 57.3 petabytes of data storage per year (Miller 2009). Other technical challenges include developing approaches to ease integrating metering equipment, smart appliances and the associated communication equipment linking the various parties involved in electricity transactions (Callahan 2007). Other hardware challenges for smart appliances include accommodating diverse operating environments such as temperature extremes and water exposure (Gabriel 2009).

A streamlined integration of DG and storage devices, as well as microgrids, requires well understood system interconnection agreements that can be replicated safely and easily. Perhaps the largest technical hurdle in moving toward a smart grid is accommodating intermittent renewable energy resources and overcoming the associated effects on grid stability; even scale and dispersion will not overcome the variability in power production. As such, innovations in storage technologies currently under development will need to become cost effective and commercialized (Kreutzer et al. 2010). The California ISO noted in their draft report on wind integration that energy ramps as high as 3,000 MW per hour or more were possible during summer peak (CAISO 2007). Until storage technologies are developed that can be shown to be cost effective, control methods at the transmission and distribution levels are extremely important.

The integration of DER makes fault detection, planning and design, and voltage regulation more difficult (Pai 2002). Voltage-regulation challenges include overvoltage issues, which can arise due to the two-way flow of electricity in the distribution system (Eynon 2002). Driesen and Belmans (2006) point out that DER will present technical hurdles in terms of frequency, voltage level, reactive power and power conditioning. DG, microgrids, and storage resources, including EVs and PHEVs, share similar monitoring and control challenges identified for demand-response metrics. The system interfaces associated with incorporating DG resources widen significantly from the traditional grid interface. Lastly, PHEVs, EVs, fuel cells, wind turbines, photovoltaics and batteries require inverters. The challenge is to bring the sources online and maintain system voltage and frequency as the inverters used to transform power from direct current (DC) generation units to alternating current (AC) power can increase harmonics in the grid (Eynon 2002).

There are additional technical barriers for EVs and PHEVs, which include those related to battery technologies, the automotive manufacturing process, limitations in range, refueling, the supply chain, and electricity infrastructure capacity. Battery technology limitations include energy intensity, durability, life span, size and weight, aspects of battery safety, the cost of manufacturing, intellectual property issues, and raw-material constraints. While this challenge continues today, EV charging stations are being installed across the U.S. and by 2015, Pike Research (2010) estimates that nearly 1 million charging stations will be in place in the U.S. with 4.7 million available worldwide. In comparison, there were approximately 159,000 retail gasoline outlets located in the U.S. in 2010 (National Petroleum News 2010).

To enable higher capacity utilization of existing transmission lines, limiting factors such as voltage instability and transient stability, which can significantly affect transmission-line transfer capacity more than the thermal limitations, must be monitored using DLR. Mayadas-Dering et al. (2010) indicate that primary among DLR challenges are: 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 in light of the vulnerability of overhead lines to extreme weather conditions.

NETL identified specific challenges including 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 ultra-clean power to PQ sensitive consumers, and deploying DG devices capable of providing clean power to local sensitive loads. Specifically, this requires technologies with 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 (NETL 2009).

4.2 Business and Financial Challenges

Some of the more important business and financial challenges include obtaining the capital to finance smart grid project deployments, followed by the ability to recover costs, customer-perception barriers, improving reliability, and improving power quality. 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 (FERC 2007b). With a smart grid, entrepreneurs may find the capital or solutions through innovation that reduce the required capital but the ability to recover costs is an important issue. Investment in smart grid projects is made more difficult when much of the data about costs and revenues are based only on research rather than field deployments. Some of the innovations to reduce the capital requirements may include AMI and the use of DG. In order for the investments to occur, favorable interconnection standards that allow for appropriate cost recovery must be developed; otherwise investments will not be made in renewable energy production, DG, microgrids and demand response equipment. Additionally, approaches need to be developed to share data to improve the use of phasor data and improve reliability. Lastly, studies need to be developed that show the benefits of PQ devices.

There are also issues surrounding capital availability in regulated versus unregulated markets. While electricity service providers operating in regulated markets tend to have greater access to capital due to the higher expectation of return, they may not have the incentive to invest in the smart grid because smart grid investments are likely to achieve efficiency gains and thereby reduce their revenue. If, on the other hand, regulators allow service providers to recover their investment through higher rates, consumers must bear the burden of higher costs. Alternatively, unregulated markets have greater volatility with the higher potential for default and thus face credit rationing with higher costs of capital; however, innovators who can demonstrate the ability of a technology to yield a positive return on investment can often find willing investors. Thus, there is a tradeoff in willingness to invest between regulated and unregulated markets.

Even though ARRA allocated billions of dollars to smart grid technology, there are still significant up-front costs to implement AMI. These include "labor costs associated with deployment and installation of new meters, customer education, and IT system integration costs" (Faruqui et al. 2009). Based on a California projection, implementing smart meters has been forecast to cost as much as $40 billion (Faruqui and Sergici 2009). The projected costs will probably increase due to varying regional requirements for AMI system features. Problematic for AMI technology are drive-by or walk-by meters (automatic meter reading or automated meter reading [AMR]) that have existed for some time and are "possibly discouraging the installation of the more demand response friendly AMI" (FERC 2007a).

Investments in AMI, which improves dynamic pricing, hinge upon energy and service providers being able to recover their investments. Service providers incur significant costs when installing AMI and updating billing systems. To date, regulatory recovery of these costs has been a contentious issue. Furthermore, the regulated retail market can be a challenge for third-party electricity aggregators and service providers who desire access to customers and dynamic-pricing markets that can support viable business plans. In addition, 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.

Quantitative assessments measuring customer responsiveness to prices are limited and investors have seen participation in most voluntary RTP programs decline in recent years. In part, the decline may be because without automated agents or controllers, consumers have to spend too much time to monitor prices in order to reduce energy costs. However, with installation of automated controllers or automated agents, customers could anticipate and take advantage of price changes to reduce their energy costs with little effort. 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. Lastly, , insufficient market transparency, has been identified as key barriers to developing functional demand response programs (FERC 2006).

In order to employ the full potential of DER, states may need to expand their existing laws or institute new ones that allow the flow of surplus energy back to the grid (Kaplan 2009). 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. 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 with lower demand for power (Venkataramanan and Marney 2008).

The challenge for states is to implement the recommendation in Section 1307 of EISA to have utilities undertake a business analysis of non-advanced grid technology with alternative qualified smart grid technology investment. State implementation of the recommendation may encourage shifting some of the large traditional investments to smart grid investments.

Education programs need to be developed that identify 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. In addition, outreach programs need to be developed for other stakeholder groups to educate them on the aspects of the smart grid that pertain to their group. As an example, end users need to be educated on what information will be provided to them from the smart grid, and how they will control the use of their electric devices. These programs will provide the value proposition of the smart grid to regulators, legislators, end users, and any other relevant groups.

Interconnection requirements must be resolved through standards such as IEEE 1547.4; otherwise seamless transitions will not occur (NC 2005). Completion of the IEEE 1547.4 standard for microgrid requirements is also needed (IEEE 2008). Based on interconnection standards measured by IREC and the NNEC, 13 states have policies favorable to grid interconnection, 15 states have neutral policies and 22 states (including those with no standard) have unfavorable policies (NNEC 2009).

On the generation side, making the grid compatible with DG, microgrids, and storage systems could be expensive for system operators with limited ability to recover their costs. 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. Service providers use standby charges to pay for natural-gas and other systems that stay on standby when intermittent DG and microgrid generation are not available. These charges for rarely-used infrastructure are a significant economic barrier to DG and microgrid deployments (Hatziargyriou 2008, Venkataramanan and Marney 2008). In addition, electricity service providers need to invest in instrumentation and communication to make the DG resources dispatchable so that local service providers and transmission operators can deal with all the technical issues associated with intermittency and control (DOE 2008).

While much progress has been made to integrate phasor data to improve reliability including software and tools into reliability and utility settings, challenges still remain for implementation at the research, planning and operational levels (Steklac 2007). In order for a smart grid to function, many different entities need to communicate and share data on load control, prices, and other elements. Yet, 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 reliability coordinators. Circumstances may require sharing of information with non-grid entities such as emergency response centers or state and federal government agencies charged with public safety, homeland security, or national defense; however, data sharing could provide operational and market intelligence to competitors that could be used in service-area and/or corporate takeovers. The data could also be used by governments and regulators to second-guess operational decisions and reduce incentives or assess penalties for outages and/or unsafe operating conditions. Data sharing also generates concerns about the security of the shared information. These inhibitions are particularly significant when operational data must be shared among peers, particularly local service providers and BAs. Approaches are needed to remove these limitations, or data sharing will be limited and in turn limit the efficiency, flexibility, and transparency of required communications.

Another challenge for the smart grid is to encourage the introduction of privacy enhancing technologies into the design of smart grid technologies (Cavoukian 2009). Privacy issues are important to all stakeholders. Privacy technologies that enable the transfer of information while protecting the privacy of the provider and the user could significantly improve the willingness of entities to provide and use the information required to enable a smart grid.

Cost effectiveness can inhibit some smart grid investments either because the benefits do not accrue to the owner or because the cost effectiveness has not been shown to date. For example Seppa (2004) notes that a significant business barrier to acceptance of dynamic line ratings which could increase transmission capacity is the presence of societal benefits that don't necessarily accrue to the investor. Dynamic ratings technology benefits the whole system, but the investors don't necessarily obtain benefits in accordance with their costs. Thus, system pricing needs to ensure that benefits accrue to the investor so that investments that are beneficial to the system allow for their recovery. Microgrids are another example of where they can mitigate many of the issues of two-way power flow, such as intermittency of renewable resources. This may need regulatory support to occur. Another relevant case involves advanced PQ devices. PQ devices are used by distribution companies to monitor and diagnose problems. The PQ devices used, as well as those used by the end user, depend on the size and type of the critical load. PQ-enhancing devices are still too expensive to be widely used. Additional cost/benefit studies could provide a more complete accounting of the full range of cost and benefits to the U.S. economy resulting from improving PQ (NETL 2009).

5.0 Recommendations for Future Reports

Smart grid technologies have continued along their development and deployment paths since the completion of the 2009 SGSR. Aided significantly by the passage of ARRA, recent investment levels in smart grid applications have expanded rapidly and are expected to continue their growth trends in the near future. Visions of an electricity system that not only provides service but also interacts and communicates with end users, including generation and storage in industrial plants, commercial businesses, and residential homes, are driving new business and policy models as well as advancements in the technologies that support them. Both the build metrics and the value metrics included in this report were designed to provide insight into recent smart grid developments and deployments while identifying challenges from both business and technical perspectives. While the research team has conducted an extensive search for data to directly measure deployment trends for each of the 21 metrics explored in this report, not all data gaps have been addressed and study shortcomings persist. The remainder of this section discusses recommendations for future reports that could address some of these shortcomings.

As the second in a series of biennial smart grid status reports required under EISA, information gathered for this document should be used in conjunction with the 2009 SGSR to form a framework and measurement baseline for future reports. The metrics identified in this report are indicators of, and in some cases proxies for, smart grid deployment progress. They are not comprehensive measures of all smart grid concerns; thus, these metrics should be reviewed in subsequent reports for continued relevance and appropriate emphasis of major smart grid attributes.

A recent report released by the National Science and Technology Council, *A Policy Framework for the 21st Century Grid*, emphasizes the importance of electricity customers being able to access their own energy data in machine readable formats as a way to spur behavioral energy efficiency as well as the development of new products and services, including greater building and appliance automation (National Science and Technology Council 2011). To track progress in this area, future reports may include a metric that measures consumer access to energy data in machine readable formats.

Metric 21 – Grid-Connected Renewable Resources was added to the report to measure the implementation of renewable electricity generation and the impact of those resources on national CO_2 emission levels. Future reports may include additional metrics, or it may be found necessary to alter existing metrics for technologies that never reached full deployment levels or were rendered obsolete by other technologies. However, care should be taken to avoid the tendency to proliferate the number of metrics or undertake extensive changes from one report to the next. In deciding whether a new metric is merited, consideration should be given to how it fits with the other metrics, whether a previous metric can be retired, and the strength of a metric's contribution to characterizing smart grid progress.

The nascent stage of many smart grid applications presents a number of measurement challenges. As these technologies, deployments, and policies continue to evolve, so should the SGSR and the metrics contained within it. While it is possible that future additions will be made in terms of the metrics examined in the SGSR, the overall time series of smart grid measurements that began in 2009 should remain as constant as possible in order to most accurately reflect changes within the industry and to enable consistent measurement of progress over time. As technologies evolve, some metrics that were initially identified as nascent, such as Metric 6 – Load Served by Microgrids, may begin to play a more significant role. As these metrics rise in significance, the manner in which they are measured may need to change to reflect a better understanding of the technologies' applications and capabilities. Other metrics, such as Metric 12 – Advanced Metering Infrastructure, may level off after full penetration. In order to recognize these traits, the SGSR should be monitored to determine the status and classification of each metric.

Due to the early stages of development and deployment of some systems, many technologies and standards evaluated in this report lack concrete definitions, causing complications and potential discrepancies in data measurements. One example, Metric 9 – Grid-Responsive, Non-Generating, Demand-Side Equipment, presents this challenge because of questions surrounding specific equipment definitions and methods for measuring deployment trends. Another metric with definitional questions is Metric 4 – Regulatory Recovery for Smart Grid Investment. To address this and other similar issues present in other metrics, future examiners may wish to work with industry and regulatory bodies to identify and provide more concrete definitions for these metrics, thus enabling a more uniform basis of measurement.

In addition, for some of the metrics, there are incomplete or no data available for quantitative analysis. Such difficulties are present in Metric 6 – Loads Served by Microgrids and Metric 9 – Grid-Responsive, Non-Generating, Demand-Side Equipment. These difficulties could cause inconsistencies in future reports. While obtaining additional information on all metrics is a primary focus during the completion of the SGSR, it is important to note that significant shortcomings in data for certain metrics result in significant barriers to rendering a clear picture of the smart grid deployment landscape.

For this report and the 2009 SGSR, interviews were conducted with electricity service providers to address these data gaps. This survey format should be retained for future reports and be revised biennially to address any new material not included in previous interviews. As more understanding regarding problematic metrics is acquired and new technologies and information are brought to bear on the matter, questionnaires for these interviews can be revised to form a more complete picture of smart grid deployment. Further, questionnaires for these interviews should be developed and distributed earlier in the study schedule to maximize the amount of time available to gather data and the level of information acquired through the interview process. Finally, additional coordination with other smart grid information collection activities (e.g., information resulting from smart grid ARRA investment grants & demonstrations, Smart Grid Information Clearinghouse, Smart Grid Maturity Model) whose products can be used in addressing data gaps should also be supported.

Besides reviewing the progress of developments for the metrics identified in this report, future reports should consider addressing the following potential improvements:

- Further evaluation of stakeholder feedback, assessment of new developments, and inclusion of additional stakeholder groups as necessary
- Further evaluation of privacy and data access policies, including consumer and third party access to data
- Further investigation and analysis of the risks and challenges organizations and individuals are facing with implementation of the various smart grid elements
- Incorporation and tracking of the consumer perspective, potentially through surveys, focus groups, or analysis of consumer responses to smart grid elements reported by electricity service providers or other groups (e.g., Smart Grid Consumer Collaborative)
- Review progress toward resolving smart grid challenges, identify new challenges, and describe places where opportunities to advance smart grid concepts are occurring

Further recommendations specific to each metric can be found in Appendix A, which presents the detailed results of investigations into the metrics. The end of each metric description includes a subsection on recommendations for that metric. This report includes a summary of those recommendations; future reports should consider a similar summation.

A final recommendation, particularly when considering this document in its entirety, pertains to the overall objective of this report. The SGSR represents a biennial snapshot of technology, business and policy advancements that at times change rapidly. Some themes that are prominent in one report, such as the impacts of ARRA, may not pertain to future ones. The characteristics and impacts of these landmark events in the evolution of a smart electric grid should be well documented in future reports.

6.0 Conclusions

The state of smart grid deployment covers a broad array of electricity system capabilities and services enabled through pervasive communication and information technology, with the objective of improving reliability, operating efficiency, resiliency to threats, and impact on the environment. By collecting information from a workshop, interviews, and research of existing smart grid literature and studies, this report attempts to present a balanced view of progress across many fronts toward a smart grid.

Significant smart grid developments taking place since completion of the 2009 SGSR were largely tied to the passage of ARRA, which designated $4.5 billion in awards for programs described under Title XIII (111 USC 405). The impacts of ARRA on metrics in the SGSR include the deployment of 877 PMUs [Metric 2 – Real-time System Operations Data Sharing], investment in manufacturing facilities for EV batteries and components [Metric 8 – EVs and PHEVs], $812.6 million in federal grant awards for AMI deployments with total project values reaching over $2 billion, and $7.2 billion in funding to expand broadband access and adoption [Metric 1-Dynamic Pricing, Metric 2-Real-time System Operations Data Sharing, Metric 12-Advanced Meters]. Other significant developments affecting the deployment trends reported in the 2010 SGSR include: expanded adoption of state renewable portfolio standards (there are now 29 states with such standards), distributed resource interconnection policies being implemented or expanded in 14 states since 2008, incentives for purchasing and owning EVs and PHEVs now in place or planned in 21 states, and NIST releasing the first phase of a three-phase plan that aims to align smart grid standards.

6.1 Progress towards Realizing the Characteristics of the Modern Grid

To convey the present state of smart grid deployment, this report uses a set of six characteristics derived from the NETL Modern Grid Initiative and documented in "Characteristics of the Modern Grid" (Miller 2008). The metrics and analysis presented in this report provide insights into progress toward these characteristics. Nearly all of the metrics contribute information to understanding multiple characteristics. The main findings are summarized below:

- **Enabling Informed Participation by Customers**: Supporting the bi-directional flow of information and energy is a foundation for enabling participation through consumer resources. AMI is receiving the most attention in terms of planning and investment. Independent analyses of AMI penetration indicate deployments nationwide expanded to an estimated 16 million in 2010, representing 10.7 percent of U.S. meters (Neichin and Cheng 2010, King 2010). In addition, state PUCs have approved an additional 34 million AMI deployments [Metric 12–Advanced Meters]. Smart grid technology, such as AMI, has enabled implementation of dynamic pricing programs across the U.S. A FERC study found that the number of service providers that reported offering some form of real-time pricing tariff to enrolled customers increased from 60 in 2006 to 315 in 2008, and service providers offering critical-peak pricing increased from 36 in 2006 to 88 in 2008 [Metric 1–Dynamic Pricing] (FERC 2009a). Lastly, the amount of participating load based on grid conditions is beginning to show a shift from traditional interruptible demand at industrial plants toward demand-response programs that either allow an energy-service provider to perform direct load control or provide financial incentives for customer-responsive demand at homes and businesses; however, as of 2008, less than 2 percent of net summer generating capacity was under load management programs [Metric 5–Load Participation Based on Grid Conditions].

- **Accommodating All Generation & Storage Options**: DER and interconnection standards to accommodate generation capacity appear to be expanding in the U.S. Distributed generation (carbon-based and renewable) and storage, although a small fraction (1 percent) of total summer capacity, appear to be increasing rapidly [Metric 7–Grid-Connected Distributed Generation]. Total DG capacity was 5,423 MW in 2004 but grew to 12,863 MW in 2008, an increase of 137 percent (EIA 2010a). To expand favorability of interconnection standards, EISA required interoperability policies to accommodate consumer distributed resources, including DG, renewable generation, energy storage, energy efficiency, and demand response (110 USC 1305). By June 2010, 39 states as well as Washington, D.C. and Puerto Rico had adopted variations of an interconnection policy [Metric 3–Distributed Resource Interconnection Policy]. Fourteen states have either imposed new policies or expanded existing interconnection standards since 2008. The percentage of utilities with standard resource-interconnection policies was based on whether the individual utilities matched their state's interconnection policies. Roughly 83.9 percent of utilities currently have a standard resource-interconnection policy in place, compared with 61 percent in 2008 (EIA 2010b). Grid-connected renewable resources [Metric 21] represent more than DG because they include wind farms and other large but decentralized sources of generation. Currently, renewable resources excluding conventional hydro have reached more than 3.5 percent of total generation and total output is expected to more than quadruple by 2030.

- **Enabling New Products, Services, & Markets**: Investment in smart grid technologies has continued to gain traction in recent years. Venture-capital funding secured by smart grid startups was estimated at $194.1 million in 2007 and $414.0 million in 2009, representing a two-year growth rate of over 113 percent (Fan 2008, Cleantech Group 2010). Deals totaling more than $1.6 billion were identified during the 2000 through 2009 timeframe [Metric 20–Venture Capital Investment]. 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. In addition to the $3.4 billion invested in smart grid matching-grant programs, ARRA also funded $327 million for research, instrumentation, and laboratory infrastructure development (DOE 2009b). A smart grid also supports the deployment of new vehicle technologies (e.g., EVs and PHEVs) [Metric 8]. Electric vehicle incentives are proliferating at the state level. Tax credits and other incentive programs are either in place or proposed in 21 states. Recent research indicates that ultimate penetration of EVs and PHEVs could reach as high as 30 to 60 percent by 2035 (Greene and Lin 2010). Regulatory rulings are becoming more inclined toward granting rate recovery for smart grid investments [Metric 4–Regulatory Rate Recovery]. New products and services from AMI programs have been significant beneficiaries of these rulings. A smart grid includes consumer-oriented "smart" equipment, such as thermostats, space heaters, clothes dryers, and water heaters that communicate to enable demand-side participation. This equipment is just emerging, primarily in pilot programs [Metric 9–Grid-Responsive Non-Generating Demand-Side Equipment].

- **Providing the Power Quality for the Range of Needs**: Not all customers have the same PQ requirements, though traditionally these requirements and the costs to provide them have been shared. The options for enhancing PQ with a smart grid cover a range of technologies and service provider program approaches (e.g., PQ meters, storage devices, microgrids) [Metric 17–Power Quality]. Various types of DG [Metric 7–Grid-Connected Distributed Generation] and energy-storage equipment can improve PQ. These technologies, which are connected to the grid, include backup generators, microturbines, combined heat and power systems, solar panels, wind turbines and a wide range of energy storage technologies, such as batteries, compressed air storage systems, flywheels, and ultracapacitors. Of the projects funded by ARRA, there are 32 with a collective value of $620 million that combine smart grid and energy storage functionalities (DOE 2009d). As mentioned earlier, deployment of DER is trending upward, while microgrid parks [Metric 6–Load Served by Microgrids] are just emerging and are mostly represented in pilot programs.
- **Optimizing Asset Utilization & Operating Efficiently**: Smart grid technologies are designed to lower operation costs, reduce maintenance costs, and expand the flexibility of operational control relative to the current grid system. This operational efficiency and improved asset utilization is driven by advanced communication and information technologies. Better monitoring and control technologies reduce the need for increased generation capacity through demand response measures and energy efficiency. The capacity factor for the U.S. [Metric 14–Capacity Factors] remained nearly unchanged from 2006 to 2008, making only a slight marginal improvement. On average, less than half of the nation's generation capacity is now used but more than 80 percent is used during summer peaks (NERC 2009a). Smart grid techniques may be able to increase asset utilization, thus increasing overall capacity factors. Data from T&D operators across the nation show a clear trend of increasing T&D automation [Metric 11] and increasing investment in these systems. From 2006 to 2008, more operators were planning increases in T&D automation

investments (41 to 43 percent) than those decreasing future expenditures (5 to 11 percent) (BusinessWire 2010). The last 50 years have seen relatively steady generation efficiency rates with relative stability of coal and petroleum production and increases in natural gas. T&D efficiency rates have also been relatively stable over the past two decades but grew from 92.3 percent in 1995 to 94.1 percent in 2008 [Metric 15–Generation and T&D Efficiencies] (EIA 2009).

- **Operating Resiliently: Disturbances, Attacks, & Natural Disasters**: The national averages for reliability indices (outage duration and frequency measures SAIDI, SAIFI, and MAIFI) appear to be trending upward [Metric 10–T&D System Reliability]. Smart-grid elements, such as demand-side resource and DG participation in system operations are expected to more elegantly respond to disturbances and emergencies. While non-generating demand-side equipment [Metric 9] remains in a nascent stage of development, programmable, communicating thermostats are a near-term success in the equipment category with numerous installations on a pilot scale being launched around the U.S. For example, an analysis performed by the CEC indicated that communicating, demand response thermostats were cost effective in 15 of 16 studied climate zones. The total discounted value of the thermostats ranged from as little as $71 to as high as $4,180 over 30 years for single family dwellings. The savings for multi-family dwellings were not as significant with only 6 of 16 climate zones deemed cost effective (California Utilities Statewide Codes and Standards Team 2011). At the regional system operations level, advanced measurement equipment is being deployed within the delivery infrastructure to support situational awareness and enhance reliability coordination. Deployment numbers for one technology, PMUs [Metric 2–Real-time System Operations Data Sharing], will grow from the current network of 200 to 1,077 due to ARRA investments (Overholt 2010). Lastly, cyber security challenges are beginning to be addressed with a more disciplined approach. In early 2008, FERC directed NERC to tighten the standards to provide for external oversight of classification of critical cyber assets and remove language allowing variable implementation of the standards. The numbers of violations related to CIP have been on the decline in the past two years, falling from as high as 306 in July 2008 to 54 in January of 2010 [Metric 18–Cyber Security].

Different areas of the country have distinctions with regard to their generation resources, their business economy, climate, topography, environmental concerns, and public policy. These distinctions influence the picture for smart grid deployment in each region, provide different incentives, and pose different obstacles to development.

6.2 Challenges to Smart Grid Deployments

Significant challenges still exist for bringing smart grid capabilities to fruition. Foremost among these challenges is the value proposition and the capital required to purchase the new technologies envisioned for communicating information between end users, energy providers, and distribution and transmission providers. Although progress has been made in the purchase and installation of PMUs and AMI deployments, estimates for advanced metering capital still range up to $40 billion despite the billions of dollars provided for smart grid funding in ARRA (Faruqui and Sergici 2009). With ARRA investments made in PMUs, the grid will be approaching the target level of PMUs to provide good coverage for grid monitoring (Overholt 2010).

Other areas of the grid including transmission, distribution, and software requirements will also need capital investment to update the grid. Entrepreneurs that can find the appropriate value propositions could lessen these significant capital requirements. However, with the rapid changes in technology, energy mixes, and energy policy, the path to a smarter grid system provides a degree of uncertainty that may not allow investors to clearly identify technologies that will yield positive returns on investment. Yet, if legislators and regulators try to legislate or regulate the smart grid's development in order to provide certainty to investors, they could inhibit technology innovations that might provide a more flexible and transparent energy market. Nevertheless, allowing the grid to develop in a free market environment without some guidance could put the energy grid and national interests at risk. Thus, the challenge is to balance enabling innovation with providing some certainty to the markets.

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-area situational awareness and control. Such progress will help to protect the grid from major failures like the 2003 blackout of the Northeast but further progress is still needed. Significant progress needs to be made in handling intermittent generation, including valuing storage technologies and making them cost effective. Storage is one approach that could smooth generation from renewable resources such as wind and solar. Studies indicate that when variable renewable resources reach 20 percent penetration, they will be difficult and expensive to manage (Pratt et al. 2010). The software and hardware required to allow this integration are making significant progress, but the integration of these programs is still in the demonstration stage. Lastly, regulations must focus on updating reliability standards, encouraging interoperability, establishing favorable interconnection standards, and developing investment recovery mechanisms for justified smart grid investments.

6.3 Recommendations for Future Reports

As the second in a series of biennial smart grid status reports required under EISA, information gathered for this document should be used in conjunction with the 2009 SGSR to form a framework and measurement baseline for future reports. Future reports may include additional metrics, or it may be found necessary to alter existing metrics for technologies that never reach full deployment levels or are ultimately rendered obsolete by other technologies.

However, care should be taken to avoid the tendency to proliferate the number of metrics or undertake extensive changes from one report to the next. In preparing this report, the research team followed the recommendation of the 2009 SGSR in defining and reviewing metrics. As a result, a small number of changes were made to the SGSR metrics as outlined previously.

Due to the early stages of development and deployment of some systems, many technologies and standards evaluated in this report lack concrete definitions, causing complications and potential discrepancies in data measurement. Future studies should consider adjustments to these definitions based on input provided by industry and regulatory bodies. In addition, there is absent or incomplete data for some of the metrics evaluated in this report. A primary focus of future reports should be closing these data gaps through interviews with electricity service providers and collaborations with private collectors of energy sector data.

Besides reviewing the progress of developments for the metrics identified in this report, future reports should consider addressing the following potential improvements:

- Further evaluate stakeholder feedback through assessment of new developments and inclusion of additional stakeholder groups as necessary
- Incorporate and track the consumer perspective
- Review progress toward resolving smart grid challenges, identify new challenges, and describe places where opportunities to advance smart grid concepts are occurring

Further recommendations specific to each metric can be found in Appendix A, which presents the detailed results of investigations into the metrics.

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