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Estimating the Costs and Benefits of the Smart Grid

A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid

2011 TECHNICAL REPORT

Estimating the Costs and Benefits of the Smart Grid

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Abstract

The present electric power delivery infrastructure was not designed to meet the increased demands of a restructured electricity marketplace, the energy needs of a digital society, or the increased use and variability of renewable power production. As a result, there is a national imperative to upgrade the current power delivery system to the higher performance levels required to support continued economic growth and to improve productivity to compete internationally. To these ends, the Smart Grid integrates and enhances other necessary elements including traditional upgrades and new grid technologies with renewable generation, storage, increased consumer participation, sensors, communications and computational ability. According to the Energy Independence and Security Act of 2007, the Smart Grid will be designed to ensure high levels of security, quality, reliability, and availability of electric power; improve economic productivity and quality of life; and minimize environmental impact while maximizing safety. Characterized by a two-way flow of electricity and information between utilities and consumers, the Smart Grid will deliver real-time information and enable the near-instantaneous balance of supply (capacity) and demand at the device level.

The primary goal of this report, which is a partial update to an earlier report (EPRI 1011001), is to initiate a stakeholder discussion regarding the investment needed to create a viable Smart Grid. To meet this goal, the report documents the methodology, key assumptions, and results of a preliminary quantitative estimate of the required investment. At first glance, it may appear the most obvious change from the 2004 report is the significant increase in projected costs associated with building the smart grid. In actuality, the increased costs are a reflection of a newer, more advanced vision for the smart grid. The concept of the base requirements for the smart grid is significantly more expansive today than it was seven years ago, and those changes are reflected in this report.

Keywords

Smart grid
Smart grid costs and benefits
Functionality
Power delivery system
Transmission
Distribution

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Section 1: Executive Summary

This report documents the methodology, key assumptions, and results of a quantitative evaluation of the investment needed (costs) for an envisioned Smart Grid, and it represents a partial update to an earlier EPRI report (EPRI TR-1011001). It also offers a preliminary estimate of benefits of implementing a Smart Grid. This report is a framework for discussing possible levels of investment to achieve a fully functioning Smart Grid. It is not a definitive analysis of all attributes or costs of enhancing the power delivery system.

What is the Smart Grid?

The Smart Grid as defined here is based upon the descriptions found in the Energy Independence and Security Act of 2007. The term “Smart Grid” refers to a modernization of the electricity delivery system so that it monitors, protects, and automatically optimizes the operation of its interconnected elements – from the central and distributed generator through the high-voltage transmission network and the distribution system, to industrial users and building automation systems, to energy storage installations, and to end-use consumers and their thermostats, electric vehicles, appliances, and other household devices.

Background

The present electric power delivery infrastructure was not designed to meet the needs of a restructured electricity marketplace, the increasing demands of a digital society, or the increased use of renewable power production. In addition, investments in expansion and maintenance are constantly being challenged, and the existing infrastructure has become vulnerable to various security threats.

Figure 1-1 illustrates today’s power system. As shown, it is primarily comprised of large central-station generation connected by a high voltage network or Grid to local electric distribution systems which, in turn, serve homes, business and industry. In today’s power system, electricity flows predominantly in one direction using mechanical controls.

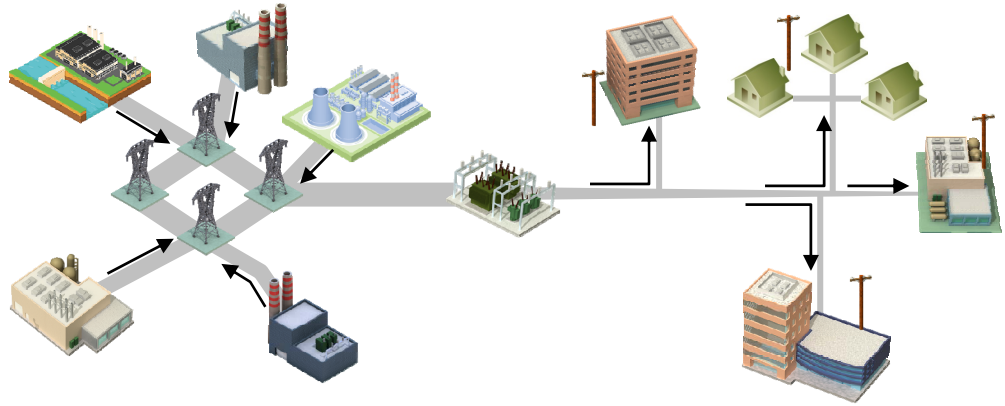


Figure 1-1
Today's Power System

Figure 1-2 illustrates the elements which will be part of a fully functional Smart Grid. The Smart Grid still depends on the support of large central-station generation, but it includes a substantial number of installations of electric energy storage and of renewable energy generation facilities, both at the bulk power system level and distributed throughout. In addition, the Smart Grid has greatly enhanced sensory and control capability configured to accommodate these distributed resources as well as electric vehicles, direct consumer participation in energy management and efficient communicating appliances. This Smart Grid is hardened against cyber security while assuring long-term operations of an extremely complex system of millions of nodes.

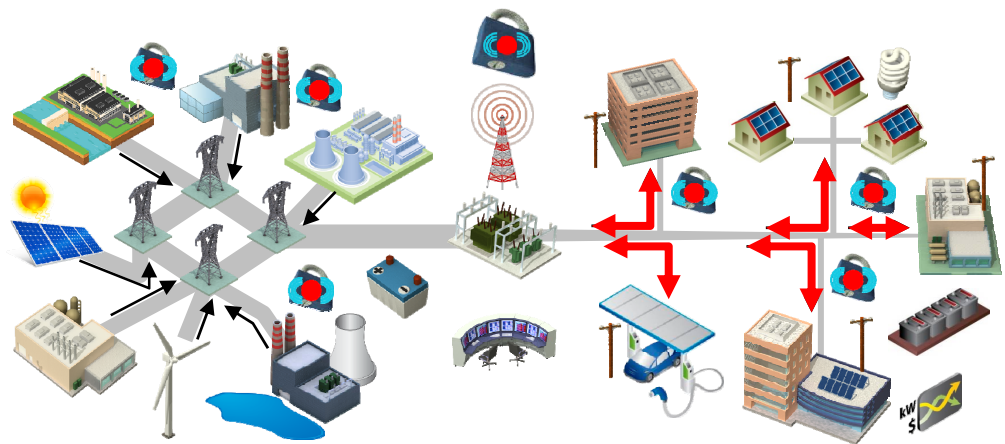


Figure 1-2
Tomorrow's Power System: A Smart Grid

As a result, there is a national imperative to modernize and enhance the power delivery system. The Smart Grid is envisioned to provide the enhancements to ensure high levels of security, quality, reliability, and availability (SQRA) of electric power; to improve economic productivity and quality of life; and to minimize environmental impact while maximizing safety and sustainability. The Smart Grid will be characterized by pervasively collaborative distributed

intelligence, including flexible wide band gap communication, dynamic sharing of all intelligent electronic devices and distributed command and control. Achieving this vision will require careful policy formulation, accelerated infrastructure investment, and greater commitment to public/private research, development, and demonstration (RD&D) to overcome barriers and vulnerabilities.

Previous Studies

Previous EPRI studies have estimated both the costs and benefits of a Smart Grid. According to an earlier study, “The Power Delivery System of the Future,” the Smart Grid would require \$165 billion in net investment (over and above investment for load growth and that needed to maintain reliability), and lead to a benefit-to-cost ratio of 4:1 (EPRI 1011001).

The Smart Grid, combined with a portfolio of generation and end-use options, could reduce 2030 overall CO₂ emissions from the electric sector by 58% relative to 2005 emissions (EPRI 1020389). A Smart Grid would be capable of providing a significant contribution to the national goals of energy and carbon savings. One EPRI report (EPRI 1016905) estimated the emissions reduction impact of a Smart Grid at 60 to 211 million metric tons of CO₂ per year in 2030.

Other EPRI studies have estimated the cost of power disturbances across all business sectors in the U.S. at between \$104 billion and \$164 billion a year as a result of outages and another \$15 billion to \$24 billion due to power quality (PQ) phenomena (EPRI 1006274). The cost of a massive blackout is estimated to be about \$10 billion per event as described in EPRI’s “Final Report on the August 14, 2003 Blackout in the United States and Canada.”

Purpose and Scope

The purpose of this study is to inform the public debate on the investment needed to create a fully functioning Smart Grid. For each key portion of the overall task, the project team selected methods based on the availability of credible information and the need to conduct a cost-effective and time-efficient study. The resulting estimates of costs remain highly uncertain and open to debate. This report is viewed as a starting point for discussion of possible levels of investment to bring the current power delivery system to the higher performance levels required for a Smart Grid.

In addition to welcoming and encouraging comments on this report, EPRI invites the participation of energy companies, universities, government and regulatory agencies, technology companies, associations, public advocacy organizations, and other interested parties throughout the world in refining the vision for the Smart Grid. Only through collaboration can the resources and commitment be marshaled to achieve the vision.

Summary of Results

Over and above the investment to meet electric load growth, Table 1-1 shows that the estimated *net* investment needed to realize the envisioned power delivery system (PDS) of the future is between \$338 and \$476 billion. The total value estimate range of between \$1,294 and \$2,028 billion; and when compared to the Future PDS cost estimate results in a benefit-to-cost ratio range of 2.8 to 6.0. Thus, based on the underlying assumptions, this comparison shows that the benefits of the envisioned Future PDS significantly outweigh the costs. At first glance, it may appear the most obvious change from the 2004 report (EPRI 1011001) is the significant increase in projected costs associated with building the smart grid. In actuality, the increased costs are a reflection of a newer, more advanced vision for the smart grid. The concept of the base requirements for the smart grid is significantly more expansive today than it was seven years ago, and those changes are reflected in this report. The project team has made every effort to capture a reasonable end-state of the Smart Grid in this report, rather than creating a snap shot that will change in another six or seven years.

Table 1-1

Summary of Estimated Cost and Benefits of the Smart Grid

	20-Year Total (\$billion)
Net Investment Required	338 – 476
Net Benefit	1,294 – 2,028
Benefit-to-Cost Ratio	2.8 – 6.0

This indicates an investment level of between \$17 and \$24 billion per year will be required over the next 20 years. The costs cover a wide variety of enhancements to bring the power delivery system to the performance levels required for a Smart Grid. The costs include the infrastructure to integrate distributed energy resources (DER) and to achieve full customer connectivity, but exclude the cost of generation, the cost of transmission expansion to add renewables and to meet load growth, and a category of customer costs for smart-grid ready appliances and devices. Table 1-2 lists major components of the total cost. As highlighted in the body of the report, the wide range in these estimates reflects the uncertainty the industry currently faces in estimating these costs and the possible reductions which may or may not occur over time.

Smart Grid Costs

Included in the estimates of the investment needed to realize the Smart Grid, there are estimated expenditures needed to meet load growth and to enable large-scale renewable power production. As part of these expenditures, the components of the expanded power system will need to be compatible with the Smart Grid.

Table 1-2
Total Smart Grid Costs

Costs to Enable a Fully Functioning Smart Grid (\$M)		
	Low	High
Transmission and substations	82,046	90,413
Distribution	231,960	339,409
Consumer	23,672	46,368
Total	337,678	476,190

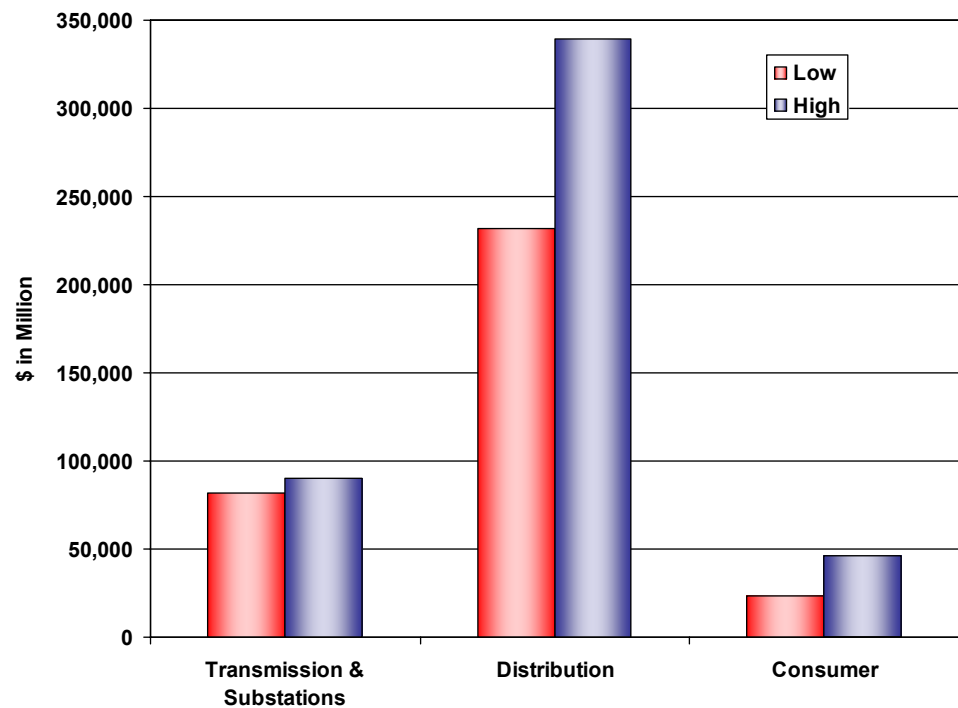


Figure 1-3
Total Smart Grid Costs

Table 1-3 summarizes one attempt to portray the consumer implications of the EPRI estimate of Smart Grid costs.

In this table, the Smart Grid costs are allocated to classes by energy (which are often what a regulatory body would mandate in the case of a regulated utility) and then calculated in several ways: (1) total Smart Grid cost divided by the number of customers for each class (a one-time payment proxy); (2) total cost per customer per year by class for 10 years for a 10-year amortization of the Smart Grid cost (in nominal, not present value, terms); and (3) the monthly equivalent

of the annual amortized cost. Finally, for the last value, the EPRI team calculated the corresponding percentage increase in the average customer monthly bill.

In practice, more complex cost allocation methods might well be applied that would shift cost among the class. This calculation assumes that the Smart Grid costs are equalized over customers across the country. However, the Smart Grid cost per customer is likely to vary considerably, and therefore, the total estimated Smart Grid cost may be more concentrated in some areas, which would raise their cost per customer in those areas and reduce it elsewhere. These costs are modest when compared to the benefits the Smart Grid will yield. However, the challenge for all of those in the electricity sector will be communicating that the Smart Grid is indeed a good investment.

Table 1-3

Possible Consumer Implications of the EPRI Estimate of Smart Grid Costs

Smart Grid Cost to Consumers – Allocated by Annual kWh (a)								
Class	\$ /Customer Total Cost (b)		\$ /Customer-Year, 10-Yr Amortization (c)		\$ /Customer-Month, 10-Yr Amortization (d)		% Increase in Monthly Bill, 10-Yr Amort (e)	
	Low	High	Low	High	Low	High	Low	High
	\$ /Customer	\$ /Customer	\$ /Cust/yr	\$ /Cust/yr	\$ /Cust/ Month	\$ /Cust/ Month		
Residential	\$1,033	\$1,455	\$103	\$145	\$9	\$12	8.4%	11.8%
Commercial	\$7,146	\$10,064	\$715	\$1,006	\$60	\$84	9.1%	12.8%
Industrial	\$107,845	\$151,877	\$10,785	\$15,188	\$899	\$1,266	0.01%	1.6%
(a) LOW refers to EPRI low estimate of \$ total SG costs; HIGH is the other SG cost. Customer numbers by class (residential, commercial industrial) are for 2009 from EIA. SG costs are allocated to customer classes based on 2009 kWh sales (38 %residential; 37% Commercial; 25% industrial). (b) Total SG cost divided by customers for each segment (residential +commercial+ industrial). (c) Annual cost per customer per year for total SG cost spread out (amortized) equally over 10 years (nominal values). (d) Annual cost per customer per month for total SG cost spread out (amortized) equally over 10 years (nominal values). (e) Annual increase in monthly bill for based on (d).								

Smart Grid Benefits

The benefits of the Smart Grid are numerous and stem from a variety of functional elements which include cost reduction, enhanced reliability, improved power quality, increased national productivity and enhanced electricity service, among others. Table 1-4 and Figure 1-4 summarize these benefits. In general terms, the Smart Grid will assure that consumers are provided with reliable, high quality digital-grade power, increased electricity-related services and an improved environment. The Smart Grid will allow the benefits resulting from the rapid growth of renewable power generation and storage as well as the increased use of electric vehicles to become available to consumers. Without the development of the Smart Grid, the full value of a lot of individual technologies like Electric Vehicles, Electric Energy Storage, Demand Response, Distributed Resources, and large central station Renewables such as wind and solar will not be fully realized.

As detailed in Chapter 2, the benefits of the Smart Grid include:

- **Allows Direct Participation by Consumers.** The smart grid consumer is informed, modifying the way they use and purchase electricity. They have choices, incentives, and disincentives.
- **Accommodates all Generation and Storage Options.** The Smart Grid accommodates all generation and storage options.
- **Enables New Products, Services, and Markets.** The Smart Grid enables a market system that provides cost-benefit tradeoffs to consumers by creating opportunities to bid for competing services.
- **Provides Power Quality for the Digital Economy.** The Smart Grid provides reliable power that is relatively interruption-free.
- **Optimizes Asset Utilization and Operational Efficiently.** The Smart Grid optimizes assets and operates efficiently.
- **Anticipates and Responds to System Disturbances (Self-heal).** The Smart Grid independently identifies and reacts to system disturbances and performs mitigation efforts to correct them.
- **Operates Resiliently against Attack and Natural Disaster.** The Smart Grid resists attacks on both the physical infrastructure (substations, poles, transformers, etc.) and the cyber-structure (markets, systems, software, communications).

Table 1-4
Estimated Benefits of the Smart Grid

Attribute	Net Present Worth (2010) \$B	
	Low	High
Productivity	1	1
Safety	13	13
Environment	102	390
Capacity	299	393
Cost	330	475
Quality	42	86
Quality of Life	74	74
Security	152	152
Reliability	281	444
Total	1294	2028

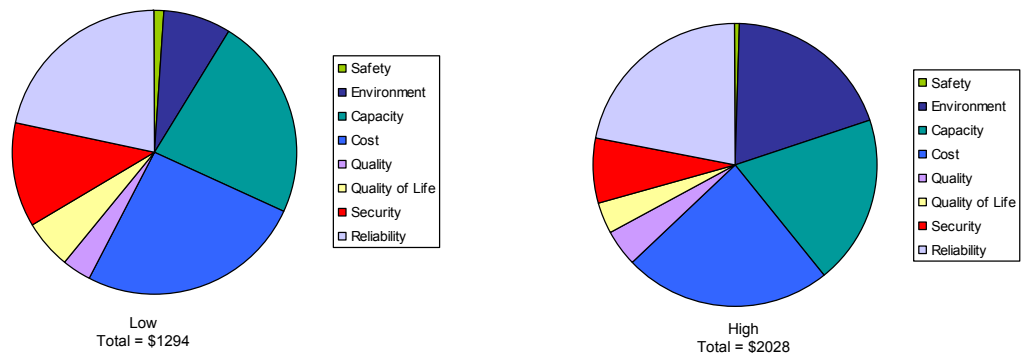


Figure 1-4
Estimated Benefits of the Smart Grid (\$ in billions)

Cyber Security

Concern has arisen recently regarding the security of an information technology regime which would be integral with tomorrow's grid. Electric utilities have been incorporating cyber security features into their operations since the early 2000s. In recent years as the Smart Grid became increasingly popular, cyber security concerns have increased significantly. While there have to date been few reliable reports of cyber attacks on power systems, there is a great deal of concern that as the grid becomes smarter and more interactive, disruption of the reliability of U.S. electricity supply will become easier.

Cyber security is an essential element of the Smart Grid. It involves the protection needed to ensure the confidentiality and integrity of the digital overlay which is part of the Smart Grid.

The project team estimates for proper cyber security protection are included in the preceding estimates. An investment of approximately \$3,729 million will be needed for the Smart Grid in addition to a related investment in information technology of approximately \$32,258 million.



Section 2: Introduction

Smart Grid Vision

This section contains a definition of Smart Grid, an outline of benefits, Smart Grid characteristics, and challenges as contained in EPRI's report to the National Institute of Science and Technology (NIST). The vision is presented as it appeared in EPRI's report to NIST (EPRI, 2009).

What is the Smart Grid?

The Smart Grid definition is based upon the description found in the Energy Independence and Security Act of 2007. The term "Smart Grid" refers to a modernization of the electricity delivery system so it monitors, protects and automatically optimizes the operation of its interconnected elements – from the central and distributed generator through the high-voltage network and distribution system, to industrial users and building automation systems, to energy storage installations and to end-use consumers including their thermostats, electric vehicles, appliances and other household devices.

The Smart Grid will be characterized by a two-way flow of electricity and information to create an automated, widely distributed energy delivery network. It incorporates into the grid the benefits of distributed computing and communications to deliver real-time information and to enable the near-instantaneous balance of supply and demand at the device level.

Smart Grid Characteristics: Drivers and Opportunities

The definition of the Smart Grid builds on the work done in EPRI's IntelliGrid Program (intelligrid.epri.com), in the Modern Grid Initiative (MGI) (NETL, 2007), and in the GridWise Architectural Council (GWAC) (gridwise.org). These considerable efforts have developed and articulated the vision statements, architectural principles, barriers, benefits, technologies and applications, policies, and the frameworks that help define the Smart Grid.

Smart Grid Benefits

Smart Grid benefits can be categorized into 5 types:

- **Power reliability and power quality.** The Smart Grid provides a reliable power supply with fewer and briefer outages, "cleaner" power, and self-

healing power systems, through the use of digital information, automated control, and autonomous systems.

- **Safety and cyber security benefits.** The Smart Grid continuously monitors itself to detect unsafe or insecure situations that could detract from its high reliability and safe operation. Higher cyber security is built in to all systems and operations including physical plant monitoring, cyber security, and privacy protection of all users and customers.
- **Energy efficiency benefits.** The Smart Grid is more efficient, providing reduced total energy use, reduced peak demand, reduced energy losses, and the ability to induce end-users to reduce electricity use instead of relying upon new generation.
- **Environmental and conservation benefits.** The Smart Grid facilitates an improved environment. It helps reduce greenhouse gases (GHG) and other pollutants by reducing generation from inefficient energy sources, supports renewable energy sources, and enables the replacement of gasoline-powered vehicles with plug-in electric vehicles.
- **Direct financial benefits.** The Smart Grid offers direct economic benefits. Operations costs are reduced or avoided. Customers have pricing choices and access to energy information. Entrepreneurs accelerate technology introduction into the generation, distribution, storage, and coordination of energy.

Stakeholder Benefits

The benefits from the Smart Grid can be categorized by the three primary stakeholder groups:

- **Consumers.** Consumers can balance their energy consumption with the real-time supply of energy. Variable pricing will provide consumer incentives to install their own infrastructure that supports the Smart Grid. Smart grid information infrastructure will support additional services not available today.
- **Utilities.** Utilities can provide more reliable energy, particularly during challenging emergency conditions, while managing their costs more effectively through efficiency and information.
- **Society.** Society benefits from more reliable power for governmental services, businesses, and consumers sensitive to power outage. Renewable energy, increased efficiencies, and Plug-In Electric Vehicle (PEV) support will reduce environmental costs, including carbon footprint.

A benefit to any one of these stakeholders can in turn benefit the others. Those benefits that reduce costs for utilities lower prices, or prevent price increases, to customers. Lower costs and decreased infrastructure requirements enhance the value of electricity to consumers. Reduced costs increase economic activity which benefits society. Societal benefits of the Smart Grid can be indirect and hard to quantify, but cannot be overlooked.

Other stakeholders also benefit from the Smart Grid. Regulators can benefit from the transparency and audit-ability of Smart Grid information. Vendors and integrators benefit from business and product opportunities around Smart Grid components and systems.

Modern Grid Initiative Smart Grid Characteristics

For the context of this section, characteristics are defined as prominent attributes, behaviors, or features that help distinguish the grid as “smart”. The MGI developed a list of seven behaviors that define the Smart Grid. Those working in each area of the Smart Grid can evaluate their work by reference to these behaviors. These behaviors match those defined by similar initiatives and workgroups.



Figure 2-1

MGI's Principle Characteristics are Part of Their Smart Grid System Vision for Measuring Success (Source: EPRI Report to NIST, 2009)

The behaviors of the Smart Grid as defined by MGI are:

- **Enable Active Participation by Consumers.** The Smart Grid motivates and includes customers, who are an integral part of the electric power system. The smart grid consumer is informed, modifying the way they use and purchase electricity. They have choices, incentives, and disincentives to modify their purchasing patterns and behavior. These choices help drive new technologies and markets.
- **Accommodate All Generation and Storage Options.** The Smart Grid accommodates all generation and storage options. It supports large, centralized power plants as well as Distributed Energy Resources (DER). DER may include system aggregators with an array of generation systems or

a farmer with a windmill and some solar panels. The same is true of storage, and as storage technologies mature, they will be an integral part of the overall Smart Grid solution set.

- **Enable New Products, Services, and Markets.** The Smart Grid enables a market system that provides cost-benefit tradeoffs to consumers by creating opportunities to bid for competing services. As much as possible, regulators, aggregators and operators, and consumers can modify the rules of business to create opportunity against market conditions. A flexible, rugged market infrastructure exists to ensure continuous electric service and reliability, while also providing revenue or cost reduction opportunities for market participants. Innovative products and services provide 3rd party vendors opportunities to create market penetration opportunities and consumers with choices and clever tools for managing their electricity costs and usage.
- **Provide Power Quality for the Digital Economy.** The Smart Grid provides reliable power that is relatively interruption-free. The power is “clean” and disturbances are minimal. Our global competitiveness demands relatively fault-free operation of the digital devices that power the productivity of our 21st century economy.
- **Optimize Asset Utilization and Operate Efficiently.** The Smart Grid optimizes assets and operates efficiently. It applies current technologies to ensure the best use of assets. Assets operate and integrate well with other assets to maximize operational efficiency and reduce costs. Routine maintenance and self-health regulating abilities allow assets to operate longer with less human interaction.
- **Anticipate and Respond to System Disturbances [Autonomously] (Self-heal).** The Smart Grid independently identifies and reacts to system disturbances and performs mitigation efforts to correct them. It incorporates an engineering design that enables problems to be isolated, analyzed, and restored with little or no human interaction. It performs continuous predictive analysis to detect existing and future problems and initiate corrective actions. It will react quickly to electricity losses and optimize restoration exercises.
- **Operate Resiliently against Attack and Natural Disaster.** The Smart Grid resists attacks on both the physical infrastructure (substations, poles, transformers, etc.) and the cyber-structure (markets, systems, software, communications). Sensors, cameras, automated switches, and intelligence are built into the infrastructure to observe, react, and alert when threats are recognized within the system. The system is resilient and incorporates self-healing technologies to resist and react to natural disasters. Constant monitoring and self-testing are conducted against the system to mitigate malware and hackers.

Smart Grid Challenges

The Smart Grid poses many procedural and technical challenges as we migrate from the current grid with its one-way power flows from central generation to dispersed loads, toward a new grid with two-way power flows, two-way and peer-

to-peer customer interactions, distributed generation, distributed intelligence, command and control. These challenges cannot be taken lightly; the Smart Grid will entail a fundamentally different paradigm for energy generation, delivery, and use.

Procedural Challenges

In the short term it will be useful to prioritize the challenges that the Smart Grid needs to overcome first as a foundation for what is to come. The industry should collaborate to segregate the challenges into buckets to test a hypothesis under which to move forward or so that addressing these challenges becomes more manageable. To address this problem, EPRI is working with several members to develop roadmaps for achieving the promise of the Smart Grid including the necessary decision trees, off ramps and schedules. These are expected to become available during 2011. The procedural challenges to the migration to a smart grid are enormous, and all need to be met as the Smart Grid evolves:

- **Broad Set of Stakeholders.** The Smart Grid will affect every person and every business in the United States. Although not every person will participate directly in the development of the Smart Grid, the need to understand and address the requirements of all these stakeholders will require significant efforts by utilities, system operators, third party electricity service providers and consumers themselves.
- **Complexity of the Smart Grid.** The Smart Grid is a vastly complex machine, with some parts racing at the speed of light. Some aspects of the Smart Grid will be sensitive to human response and interaction, while others need instantaneous, intelligent and automated responses. The smart grid will be driven by forces ranging from financial pressures to environmental requirements.
- **Transition to Smart Grid.** The transition to the Smart Grid will be lengthy. It is impossible (and unwise) to advocate that all the existing equipment and systems to be ripped out and replaced at once. The smart grid supports gradual transition and long coexistence of diverse technologies, not only as we transition from the legacy systems and equipment of today, but as we move to those of tomorrow. We must design to avoid unnecessary expenses and unwarranted decreases in reliability, safety, or cyber security.
- **Ensuring Cyber Security of Systems.** Every aspect of the Smart Grid must be secure. Cyber security technologies and compliance with standards alone are not enough to achieve secure operations without policies, on-going risk assessment, and training. The development of these human-focused procedures takes time—and needs to take time—to ensure that they are done correctly.
- **Consensus on Standards.** Standards are built on the consensus of many stakeholders over time; mandating technologies can appear to be an adequate short cut. Consensus-based standards deliver better results over.
- **Development and Support of Standards.** The open process of developing a standard benefits from the expertise and insights of a broad constituency.

The work is challenging and time consuming but yields results more reflective of a broad group of stakeholders, rather than the narrow interests of a particular stakeholder group. Ongoing engagement by user groups and other organizations enables standards to meet broader evolving needs beyond those of industry stakeholders. Both activities are essential to the development of strong standards.

- **Research and Development.** The smart grid is an evolving goal; we cannot know all that the Smart Grid is or can do. The smart grid will demand continuing R&D to assess the evolving benefits and costs, and to anticipate the evolving requirements.
- **Having a Critical Mass.** It is unclear to the EPRI project team if the Smart Grid implementation is subject to considerations like those of critical mass needed, tipping points and penetration of implementation. There is some concern that early efforts must yield benefits in order to gather support for the development. That support may not accrue until a critical number of consumers are on board with the concepts. If everything the industry does in building the Smart Grid is amenable to a slow diffusion model for evolution as opposed to undertaking some elements in a concentrated way, those benefits may not be revealed quickly enough.

Technical Challenges to Achieving the Smart Grid

Technical challenges include the following:

- **Smart Equipment.** Smart equipment refers to all field equipment which is computer-based or microprocessor-based, including controllers, remote terminal units (RTUs), and intelligent electronic devices (IEDs). It includes the actual power equipment, such as switches, capacitor banks, or breakers. It also refers to the equipment inside homes, buildings and industrial facilities. This embedded computing equipment must be robust to handle future applications for many years without being replaced.
- **Communication Systems.** Communication systems refer to the media and to the developing communication protocols. These technologies are in various stages of maturity. The smart grid must be robust enough to accommodate new media as they emerge from the communications industries, while preserving interoperable, secured systems.
- **Data Management.** Data management refers to all aspects of collecting, analyzing, storing, and providing data to users and applications, including the issues of data identification, validation, accuracy, updating, time-tagging, consistency across databases, etc. Data management methods which work well for small amounts of data often fail or become too burdensome for large amounts of data—and distribution automation and customer information generate lots of data. Data management is among the most time-consuming and difficult task in many of the functions and must be addressed in a way that can scale to immense size.
- **Cyber Security.** Cyber security addresses the prevention of damage to, unauthorized use of, exploitation of, and, if needed, the restoration of

electronic information and communications systems and services (and the information contained therein) to ensure confidentiality, integrity, and availability.

- **Information/Data Privacy.** The protection and stewardship of privacy is a significant concern in a widely interconnected system of systems that is represented by the Smart Grid. Additionally, care must be taken to ensure that access to information is not an all or nothing at all choice since various stakeholders will have differing rights to information from the Smart Grid.
- **Software Applications.** Software applications refer to programs, algorithms, calculations, and data analysis. Applications range from low level control algorithms to massive transaction processing. Application requirements are becoming more sophisticated to solve increasingly complex problems, are demanding ever more accurate and timely data, and must deliver results more quickly and accurately. Software engineering at this scale and rigor is still emerging as a discipline. Software applications are at the core of every function and node of the Smart Grid.

Smart Grid Networking

The Smart Grid is a network of networks, including power, communications and intelligence. That is, many networks with various traditional ownership and management boundaries are interconnected to provide end-to-end services between stakeholders and in and among intelligent electronic devices (IEDs).

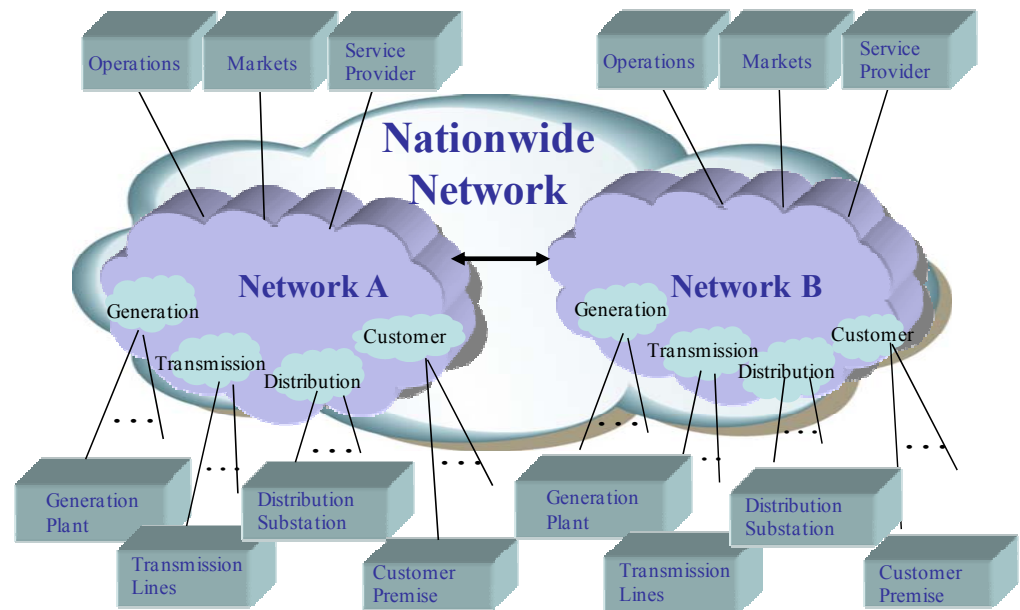


Figure 2-2
Smart Grid Networks for Information Exchange (Source: EPRI Report to NIST, 2009)

Figure 2-2 is a high level view of the information network for the Smart Grid. It handles the two-way communication between the network end points residing in

their respective domains. By domain, we mean the unique distributed computing environments in which communicating end points can be found (see next section). Thus, any domain application could communicate with any other domain application via the information network, subject to the necessary network access restrictions and quality of service requirements.

The applications in each domain are the end points of the network as shown on the top and bottom of Figure 2-2. For example, an application in the Customer domain could be a smart meter at the customer premise; an application in the Transmission domain could be a phasor measurement unit (PMU) unit on a transmission line or in a Distribution domain at a substation; an application in the Operation domain could be a computer or display system at the operation center. Each of these applications has a physical communication link with the network. The smaller clouds within the network represent sub-networks that may be implementing unique functionality. The networking function in the Operations, Market, Service Provider domains may not be easily differentiated from normal information processing networks; therefore no unique clouds are illustrated.

This information network may consist of multiple interconnected networks as shown in Figure 2-2, where two backbone networks, A and B are illustrated. The physical links within these two networks and between the network and the network end points could utilize any appropriate communication technology currently available or yet to be developed.

Additional requirements for the information network are as follows:

- Management functionality for network status monitoring, fault detection, isolation, and recovery,
- Secure protocols to protect Smart Grid information in transit and authenticate infrastructure components,
- Cyber security countermeasures,
- Addressing capability to entities in the network and devices attached to it,
- Routing capability to all network end points,
- Quality of service support for a wide range of applications with different latency and loss requirements.

The Smart Grid Conceptual Model

The Smart Grid Conceptual Model is a diagram and description that are the basis for discussing the characteristics, uses, behavior, interfaces, requirements and standards of the Smart Grid. This does not represent the final *architecture* of the Smart Grid; rather it is a tool for describing, discussing, and developing that architecture. The conceptual model provides a context for analysis of interoperation and standards, both for the rest of this document, and for the development of the architectures of the Smart Grid. The top level of the conceptual model is shown in Figure 2-3.

Conceptual Model

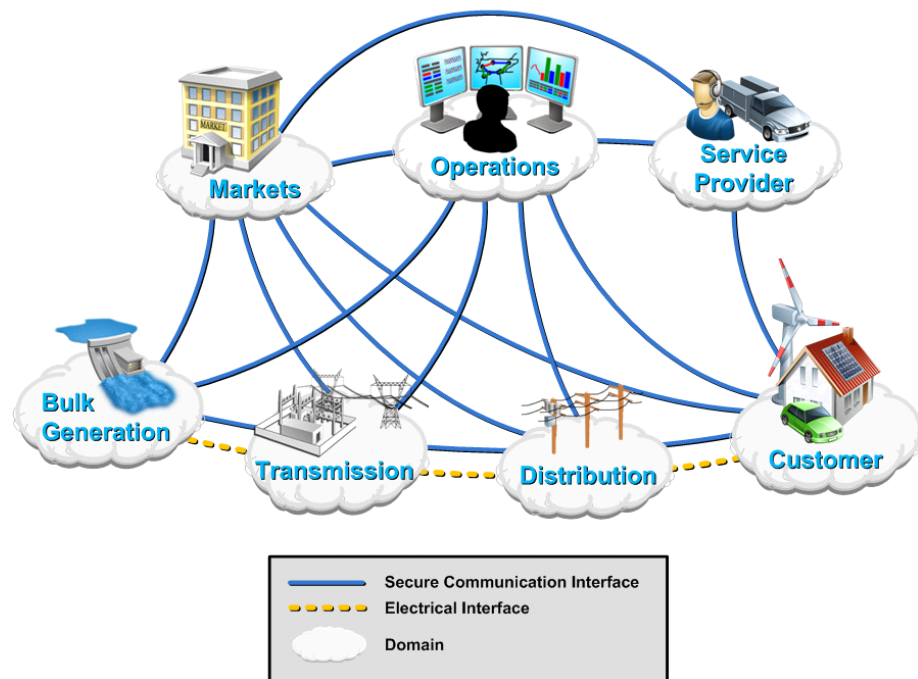


Figure 2-3

Smart Grid Conceptual Model – Top Level (Source: EPRI Report to NIST, 2009)

The conceptual model consists of several *domains*, each of which contains many *applications* and *actors* that are connected by *associations*, which have *interfaces* at each end:

- **Actors** may be devices, computer systems or software programs and/or the organizations that own them. Actors have the capability to make decisions and exchange information with other actors through interfaces.
- **Applications** are the tasks performed by the actors within the domains. Some applications are performed by a single actor, others by several actors working together.
- **Domains** group actors to discover the commonalities that will define the interfaces. In general, actors in the same domain have similar objectives. Communications within the same domain may have similar characteristics and requirements. Domains may contain other domains.
- **Associations** are logical connections between actors that establish bilateral relationships. At each end of an association is an *interface* to an *actor*.
- **Interfaces** show either electrical connections or communications connections. In the diagram, electrical interfaces are shown as yellow lines and the communications interfaces are shown in blue. Each of these interfaces may be bi-directional. Communications interfaces represent an information exchange between two domains and the actors within; they do not represent

physical connections. They represent logical connections in the smart grid information network interconnecting various domains (as shown in Figure 2-2).

The domains of the Smart Grid are listed briefly in Table 2-1 and discussed in more detail in the sections that follow. In Figure 2-3, domains are shown as clouds.

*Table 2-1
Domains in the Smart Grid Conceptual Model*

Domain	Actors in the Domain
Customers	The end users of electricity. May also generate, store, and manage the use of energy. Traditionally, three customer types are discussed, each with its own domain: home, commercial/building, and industrial.
Markets	The operators and participants in electricity markets
Service Providers	The organizations providing services to electrical customers and utilities
Operations	The managers of the movement of electricity
Bulk Generation	The generators of electricity in bulk quantities. May also store energy for later distribution.
Transmission	The carriers of bulk electricity over long distances. May also store and generate electricity.
Distribution	The distributors of electricity to and from customers. May also store and generate electricity.

It is important to note that domains are NOT organizations. For instance, an ISO or RTO may have actors in both the Markets and Operations domains. Similarly, a distribution utility is not entirely contained within the Distribution domain – it is likely to also contain actors in the Operations domain, such as a Distribution Management System, and in the Customer domain, such as meters

Additional Challenges

Work Force Issues

The utility work force is undergoing a significant challenge. One-half of the 500,000 to 600,000 utility workers will be eligible to retire in the next five years. They need to be replaced with a trained and motivated work force. Introducing Smart Grid technologies requires employees with different skills to support the implementation, maintenance, and operation of the systems with digital components. Accomplishing this when it is already difficult to get highly skilled employees with technical experience will be challenging. In addition, these staffing requirements must be met at the same time as utilities reduce their work forces in order to hold the line on costs (Lave, 2007.) This report includes the labor costs associated with installation of Smart Grid devices and software as well

as the differential maintenance. However, it does not include costs for a workforce which generally has different skills involving more expertise in digital devices and communications.

Outage management systems can be used to save costs associated with incorrect outage reports by verifying power outages at customer facilities. (PECO estimates that it avoided 7,500 crew dispatches in 2005 because it was able to see that the customer-reported outage was inaccurate (PECO, 2006).

Regulatory Challenges to Achieving the Smart Grid

Smart Grid technologies offer unprecedented challenges to regulators in encouraging and adjudicating decisions regarding Smart Grid investments. Power systems have largely operated without “smart” technology for decades. In fact, many power systems operate at 99.999% reliability at the bulk transmission level. As long as reliability levels have been maintained (the lights were still on) and costs were low (rates have been essentially flat for decades), it is conceptually difficult to understand how a basket of digital-based technologies can improve the current value of today’s power system.

New regulatory and business models are being considered which would offer a greater incentive for utilities to engage in energy efficiency. In some cases, they may be faced with reducing rates as part of seeking approval for Smart Grid investments and, subsequently, losing revenue. Regulated utilities are increasingly embracing energy-efficiency measures on the distribution system or those involving end-use customers.

An additional regulatory challenge is to understand the incremental value of Smart Grid investments. Often, for logical reasons, Smart Grid technologies are implemented in stages, with each stage requiring a business plan for regulators to approve. However, the benefits of many of the Smart Grid efforts come from the synergistic applications of a portfolio of Smart Grid technologies.

This issue was summarized nicely by the Illinois Commerce Commission in a recent report (ISSGC, 2010):

“The issue of smart grid cost recovery has been a matter of controversy and litigation for several years. Disagreements exist about whether recovery of a utility’s smart grid costs should be restricted to the ‘traditional’ rate-base method, or whether a ‘non-traditional’ method (e.g., ‘rider’ recovery) should be used.

Some stakeholders are concerned that utility proposals for cost recovery of smart grid investments would lead to significantly higher monthly bills and a shift in the risk of investment from utilities to ratepayers. Others believe that non-traditional cost recovery would be essential to accelerate deployment of smart grid technologies.”

Finally, regulators and utilities are accustomed to utility asset life in the range of 30 to 50 years and business plans and rate cases for regulated utilities are typically based on that supposition. When digital equipment is involved – particularly at the early stages of evolution – the depreciation rates for a significant amount of capital investment may be 5 to 15 years. Appropriate depreciation rates must be allowed in order to pay for asset renewal without increasing costs more than necessary.

In short, a forward view of technology must be embraced by utilities and regulators in order for the Smart Grid to be successful.

Drivers of Smart Grid Investment

A wide variety of policies and economic trends have begun to stimulate and drive U.S. investment in Smart Grid technology, including:

- **The Energy Independence and Security Act (EISA) of 2007** established national policy for grid modernization, created new federal committees, defined their roles and responsibilities, and provided incentives for investment.
- **The American Recovery and Reinvestment Act of 2009** provided more than \$3.4 billion in stimulus funding for Smart Grid technology development and demonstration, plus \$615 for Smart Grid storage. In October, 2009, 100 Smart Grid Investment Grants were awarded. These were 50/50 matching grants over a three-year period leading to an infusion of \$7 to \$8 billion in Smart Grid investments that are specifically targeted at projects that can be emulated by others.
- **Renewable portfolio standards** have been established in 30 states plus the District of Columbia stimulating rapid expansion of renewable technology and accelerating the need for Smart Grid technology for grid integration. EPRI's Prism analysis anticipates 135 GW of renewables by 2030 (EPRI 1020389). A number of states have also enacted policies to address specific environmental concerns.
- **Smart Grid interoperability standards**, called for by the EISA, moved forward with NIST's release in September, 2009, of a roadmap for interoperability standards. NIST's efforts were aided by EPRI's draft interim roadmap report released in August, 2009. While not a driver of Smart Grid investment of itself, these recommended standards facilitate Smart Grid deployment.
- **Critical Infrastructure Protection (CIP) Cyber Security Standards**, maintained by the North American Electric Reliability Corporation (NERC) and approved by the Federal Energy Regulatory Commission (FERC) in 2006, are intended to ensure the protection of the critical cyber assets that control or effect the reliability of North America's bulk electric systems. The CIP Cyber Security Standards are mandatory and enforceable across all users, owners, and operators of the bulk power system (LogRhythm, 2009).

- **Demand response programs** have accelerated. The Federal Energy Regulatory Commission's (FERC's) 2008 Demand Response (DR) and Automated Metering Infrastructure (AMI) Survey indicated that advanced metering penetration reached 4.7% of total meters, up from less than 1% in 2006, and that 8% of U.S. customers were currently involved in DR programs. DR continues to gain ground through state legislative initiatives and utility regulation. FERC's "A National Assessment of Demand Response Potential – Staff Report" in June 2009 and FERC's staff report "National Action Plan on Demand Response" in June 2010 highlight the potential (FERC, 2009 and 2010).
- **Market demand** for Smart Grid technologies has drawn the interest of many major information technology companies, from Cisco and Intel, to Google, IBM, and Microsoft which want to participate in one of the most attractive business opportunities of the future. The Smart Grid is viewed as the market equivalent of the Internet in terms of its trillion-dollar potential worldwide. It is the enabling infrastructure for the accelerated deployment of electric vehicles and plug-in hybrid electric vehicles. In addition, consumers will be a driving force in shaping the nature of tomorrow's Smart Grid technologies as they respond to evolving offerings by equipment providers.
- **Venture capital** is also entering the Smart Grid domain in a large way, promising to bring faster and more concentrated technical innovation in the areas of Automated Metering Infrastructure (AMI), communications and network technologies. More than \$1 billion in VC funding has been extended to key startups, typified by GridPoint and Silver Spring Networks (Green tech media, 2010).
- **Smart Grid roadmaps** are being developed by many electric utilities to optimize their investment strategy going forward. Objectives and starting points vary from company to company, and the optimal pathway difficult to assess. EPRI has been working with SCE, FirstEnergy, and SRP, among others, to create roadmaps for Smart Grid investment. What is critical today is reliable data on benefits from Smart Grid demonstrations. Every effort must be made to measure the actual benefits realized through Smart Grid demonstrations as projects are deployed.
- **National transmission corridors** have been identified. The Energy Policy Act of 2005 authorized the DOE to conduct national electric transmission congestion studies and to designate National Corridors if appropriate. In 2007, DOE designated a Mid-Atlantic National Corridor and a Southwest Area National Corridor (DOE, 2007).
- **Outage prevention** becomes increasingly important in an information-service-based economy. There have been five major blackouts in the last 40 years, three of which occurred in the last decade. The Northeast blackout of 2003 resulted in an estimated \$7 to \$10 billion in losses to the region. Less disruptive but more pervasive power quality problems are estimated to now cost the U.S. \$119 to \$188 billion per year (EPRI 1006274).

Previous Studies by EPRI

EPRI has been involved in collaborative, electricity-based innovation in what is now called the Smart Grid since the mid-1980s. EPRI has acted as the catalyst for a process of engagement and consensus building among diverse parties within and outside the electricity enterprise. This effort continues.

Previous EPRI studies have estimated both the costs and benefits of a Smart Grid.

- According to a 2004 study, “The Power Delivery System of the Future” will require \$165 billion in net investment (over and above investment for load growth and correcting deficiencies), and lead to a benefit-to-cost ratio of 4:1. Benefits accrue from:
 - Reduced energy losses and more efficient electrical generation.
 - Reduced transmission congestion.
 - Improved power quality.
 - Reduced environmental impact.
 - Improved U.S. competitiveness, resulting in lower prices for all U.S. products and greater U.S. job creation.
 - Fuller utilization of grid assets.
 - More targeted and efficient grid maintenance programs.
 - Fewer equipment failures.
 - Increased security through deterrence of organized attacks on the grid.
 - Improved tolerance to natural disasters.
 - Improved public and worker safety.
- EPRI studies show the annual cost of power disturbances to the U.S. economy ranges between \$119 and \$188 billion per year (EPRI 1006274). The societal cost of a massive blackout is estimated to be in the order of \$10 billion per event as described in a report published by the North American Electric Reliability Corporation titled “Final Report on the August 14, 2003 Blackout in the United States and Canada” (NERC, 2004)
- The Smart Grid is capable of providing a significant contribution to the national goals of energy and carbon savings, as documented in two recent reports.
 - One report by EPRI states that the emissions reduction impact of a Smart Grid is estimated at 60 to 211 million metric tons of CO₂ per year in 2030.
 - Another report by Pacific Northwest National Laboratory (PNNL) states that full implementation of Smart Grid technologies is expected to achieve a 12% reduction in electricity consumption and CO₂ emissions in 2030.
- And in another report, EPRI estimated that the Smart Grid, combined with a portfolio of generation and end-use options, could reduce 2030 annual CO₂ emissions from the electric sector by 58% relative to 2005 emissions (EPRI 100389).

EPRI Demonstrations

EPRI's Smart Grid Demonstration initiative involves a number of ongoing projects to demonstrate the potential for integrating distributed power generation, storage, and demand response technology into "virtual power plants." Demonstrations include both utility side and customer side technologies, and are intended to address the challenges of integrating distributed Energy resources (DER) in grid and market operations, as well as in system planning. The program addresses key industry challenges, such as:

- Demonstrating effective ways of integrating different forms of distributed resources.
- Demonstrating multiple levels of integration and interoperability among various components.
- Exploring existing and emerging information and communication technologies.

The demonstrations are taking place at a number of U.S. locations and will include a variety of feeder constructions, climate zones, and technologies. Individual demonstrations are focused on the integration of specific feeder types used in residential neighborhoods, in a mixture of residential and commercial customers, and in areas with mostly commercial customers.

Purpose of this Report

The primary purpose of this report is to initiate a discussion and debate of the investment needed to create a viable Smart Grid. To meet this objective, this report documents the methodology, key assumptions, and results of a preliminary quantitative estimate of the needed investment (cost). The report is a starting point intended to encourage further stakeholder discussion of this topic.

The complexity of the power delivery system and the wide range of potential technology applications and configurations to enhance its performance complicate the process of quantitatively estimating the needed investment. In addition, due to the various types of information available, complexity of subparts of the analysis, and uncertainties associated with estimating techniques, no single approach can be applied to all portions of the evaluation. Nevertheless, the debate over the appropriate level of power delivery system investment cannot be advanced without some preliminary estimate of costs. Hence, for each key portion of the overall task, the project team selected methods based on the availability of credible information and the need to conduct a cost-effective and time-efficient study. The resulting estimates of costs are highly uncertain and open to debate.

In this report, EPRI will only address the aggregate cost of the Smart Grid. A separate study has been launched to thoroughly assess the benefits. However, a preliminary update of benefits is included in Section 4.

Why Did the Smart Grid Cost Estimates Change?

There are a number of reasons these estimates changed so dramatically since EPRI last estimated the potential costs of the Smart Grid. First, these changes are due in part to inflation and increasing component costs. Second, they are due to a considerable expansion in the functionality now envisioned in tomorrow's Smart Grid. Table 2-2 highlights these changes.

Table 2-2

Major Elements of Functionality Added to the Smart Grid

Element	Previously Included	Added Benefits
Demand Response	None	Reduced need for generation capacity. Reduced demand for electricity.
Facilitating Renewables	None	Reduced environmental impact of electricity generation.
Plug-In Electric Vehicles or Plug-In Hybrid Electric Vehicles (PEVs)	None	Reduced environment impact from displaced fossil fuels. Grid support (increased system flexibility/ancillary services).
Energy Efficiency	Cost reduction. Reduced need for T&D. Reduced environmental impact.	Reduced need for generation capacity.
Enhanced Energy Efficiency* (additional energy efficiency)	None	Reduced costs. Reduced environmental impact.
AMI	None	AMI-related cost reductions.
Distributed Generation	None	Reduced need for central generating capacity.
Storage	None	Capacity. Reliability and power quality. O&M. Congestion management.

*Enhanced Energy Efficiency includes:

- Continuous Commissioning of Large Commercial Buildings
- Direct Feedback on Energy Usage
- Energy Savings Corresponding to Peak Load Management
- Energy Savings Corresponding to Enhanced M&V Capability



Section 3: Approach

The project team separated the power delivery system into distinct functional areas, and made a number of assumptions about technology development, deployment, and cost over the study period (2010–2030). These assumptions are covered at a high level in this section, and then covered in greater detail for each of the 25 cost components of the four main technology sections of the report – transmission, substations, distribution and customers.

What Constitutes the Power Delivery System?

The power delivery system includes the busbar located at the generating plant (where the power delivery system begins) and extends to the energy-consuming device or appliance at the end user. This means that the power delivery system encompasses generation step-up transformers; the generation switchyard; transmission substations, lines, and equipment; distribution substations, lines, and equipment; intelligent electronic devices; communications; distributed energy resources located at end users; power quality mitigation devices and uninterruptible power supplies; sensors; energy storage devices; and other equipment.

Inadequacies in the power delivery system are manifested in the form of poor reliability, excessive occurrences of degraded power quality, vulnerability to mischief or terrorist attack, the inability to integrate renewables, and the inability to provide enhanced services to consumers.

What Differentiates Smart Grid Enhancement?

Meeting the energy requirements of society will require the application across the entire power delivery system of a combination of current and advanced technologies, including but not limited to the following:

- Automation: the heart of a “smart power delivery system.”
- Communication architecture: the foundation of the power delivery system of the future and the enabler of Smart Grid integration.
- Distributed energy resources and storage development and integration.
- Power electronics-based controllers and widely dispersed sensors throughout the delivery system.
- An advanced metering infrastructure.

- A consumer portal that connects consumers and their equipment with energy services and communications entities.
- Power market tools – information systems which enable fluid wholesale power markets.
- Technology innovation in electricity use.
- Appliances and devices which are demand-response ready.

Developing an optimal combination of these technologies will require a significant, sustained RD&D investment. Making such an investment in a critical industry like the U.S. electric power industry is not unprecedented.

Study Steps

To conduct a preliminary quantitative estimate of the level of investment needed over the next 20 years, the project team first separated the core technologies into four broad areas: transmission, substations, distribution and the customer interface. Next, the team subdivided the estimating process into the following segments:

- **Meeting load growth and correcting deficiencies** via equipment installation, upgrading, and replacement to accommodate new customers (new connects), to meet the increasing energy needs of existing customers as their load grows, and to correct deficiencies (e.g., correct power flow bottlenecks and limit high-fault currents that damage critical grid equipment).
- **The Smart Grid:** The project team estimated the investment needed to develop and deploy advanced technologies needed to enhance the functionality of the power delivery system to achieve the level of a Smart Grid.

The first segment represents investments required to maintain adequate capacity and functioning of the existing power delivery system, while the second segment is the additional cost to elevate this system to that of a Smart Grid.

Key Assumptions

The cost estimate was built upon a number of key assumptions:

- Incorporate technologies that not only make the electricity delivery system smarter, but also stronger, more resilient, adaptive, and self-healing.
- Include every reasonable and cost-effective enhancement to accommodate regulatory mandates:
 - Consistent with the functionality requirements of the Energy Independence and Security Act (EISA) of 2007.
 - Meets reasonable cost-benefit assessment.

- Meets North American Electric Reliability Corporation (NERC) reliability standards, maintaining or enhancing today's reliability levels (1 day in 10 years loss of load probability or LOLP).
- Meets System Average Duration Interruption and System Average Interruption Frequency (SADI/SAFI) state guidelines normally suggest 100 minutes SADI/SAFI and power quality (PQ) events to remain at today's levels or to improve.
- Meets performance rate-making targets.
- Meets requirements of future renewable portfolio standards (RPS).
- Incorporate technology and policies that enhance Smart Grid functionality while meeting load growth, expanding and modernizing the power delivery system.
 - Enable a fully functional power delivery system
 - Enable consumer connectivity and service enhancement
 - Enable integration of distributed energy resources
- Accommodate expansion of renewable energy resources consistent with PRISM and other EPRI scenarios, and affords the possibility of meeting DOE targets for wind.
 - EPRI Prism estimates 135GW of renewables by 2030
 - DOE's aggressive target for wind—20% by 2030 seems increasingly plausible.
- The Energy Information Agency's Annual Energy Outlook 2010 projects that the annual growth rate in electricity for the period 2008 to 2035 is projected to be 1.0%. This is as a result of “structural changes in economy – higher prices – standards – improved efficiency” (EIA, 2009). EPRI estimates that the programs and activities which are part of the Smart Grid as envisioned in this report have the potential to reduce this growth rate to 0.68% per year. In addition, EPRI estimates that peak demand's growth rate will be 0.53% per year (EPRI 1016987). These growth rates were used in assumptions about the increasing needs for assets to serve consumers.
- Assume simultaneous deployment of Smart Grid functionality. While deployments will realistically be made along parallel paths and in discrete steps, this study assumes they will occur simultaneously and continuously.
- Assume steady rate of deployment. Deployments are assumed to begin in 2010. Deployment of most technologies will be made at a rate of 1/20th of the maximum assumed penetration each year over the 20-year period. Enhancement and modernization will continue after 2030.
 - The Smart Grid will never be finished. It will continue to evolve organically, not as a step function and not as a “revolution,” but as new technology becomes available, practicable and reliable.

- The investigators recognize that investments in Smart Grid will not be made linearly over 20 years, or necessarily even within 20, and will not be uniformly distributed around the country.
- Total power delivery investment costs will exceed Smart Grid investments. They will include investments to meet load growth and to maintain reliability.
- Technology costs are likely to decrease while performance levels increase in unforeseen, and possibly dramatic, ways over the next 20 years. Reasonable estimates have been made, but they are likely to prove conservative given the rapid pace of technological advances. Historically, massive technology advances such as implied by the Smart Grid are invariably driven by a single breakthrough innovation. Smart Grids don't have just one; instead they have a wide range of ideas – some at the pilot or even experimental stage. In some sense, communications, control, and computational ability is one such set of breakthroughs. However, other advances in storage, power electronics, and sensors are still needed to complete the mosaic this report paints.
- Appropriately consider operating and maintenance (O&M) costs associated with running utilities which deploy Smart Grid technologies. O&M expenses are a substantial part of total costs and are built into rates at estimated levels. The IT and technology O&M aspects of the Smart Grid need to be included in cost estimates.
- As the smart grid evolves communications networks will become more ubiquitous and multi-purpose. Utilities may use commercial carriers to provide these networks or they may build out their own networks using dedicated spectrum, share spectrum dedicated to public safety or use unlicensed spectrum. Cost varies significantly for each approach. For this study we have assessed the overall cost for communications networks and have allocated it to the various domains and smart grid applications.

Smart Grid Costs are Particularly Hard to Estimate

Smart Grids are by their nature difficult to estimate for several reasons:

- They frequently involve the integration of digital technology – Sometimes virtually embedded transmission and distribution assets have different failure rates and life expectancy than the majority of today's grid technologies. These failures and resultant replacement rates must be estimated. Utilizing a reliable component, like a substation transformer, with a 40-year design life and incorporating an information technology with 10, 15 or 20 life forces careful consideration of the costs to upgrade the embedded components.
- The obsolescence of digital technology is rapid. Increasingly complex and expanding communications and computational ability makes it possible to render Smart Grid components obsolete or inoperable with respect to the rest of the information and communications technology (ICT) system well before the end of their life. Therefore, reasonable replacement costs must be estimated.

- The improvement in Smart Grid technologies and projected decreases in their costs will occur at a greater rate than “conventional” technology.
- Uncertainty in performance – Many Smart Grid technologies are relatively new and unproven. If their performance is marginal or degrades unexpectedly over time, the entire business plan for the technology could be undermined.
- Smart Grid component costs are declining rapidly. As these technologies mature and as production volumes increase, the marginal costs of Smart Grid technologies have the potential to decline rapidly.

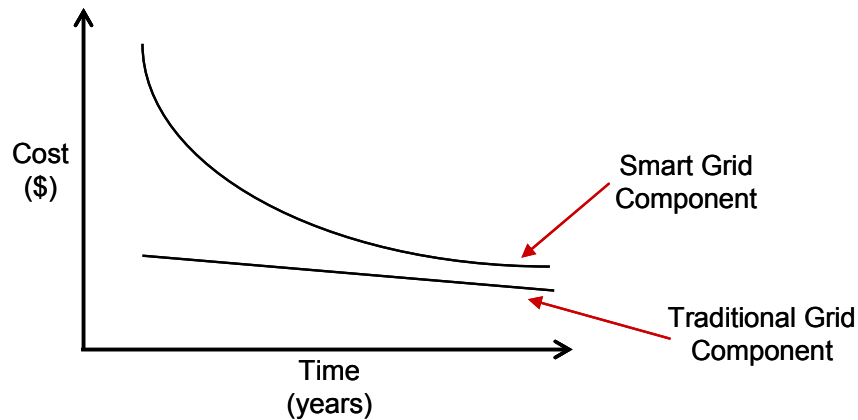


Figure 3-1
Grid Component Costs (Illustrative)

Technology Assessment: What’s In and What’s Not In?

Table 3-1 summarizes what has been included in the cost analysis and what has not been included. For the most part, T&D line expansion to meet load growth has been excluded.

Figure 3-2 illustrates the scope of the cost estimates included in this report. Investments traditionally made by customers, such as appliances and hybrid vehicles, have been excluded. However, infrastructure integration costs are included.

Table 3-1
Technologies Included and Excluded in the Cost Estimates

Technologies	Costs Included in This Analysis	Costs Excluded
1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.	Sensors, communications and computational ability	None
2. Dynamic optimization of grid operations and resources, with full cyber-security.	All grid-related	None
3. Deployment and integration of distributed resources: storage and generation, including renewable resources.	All integration costs	New transmission lines including those to integrate renewables; and costs of renewable power generation technology*
4. Development and incorporation of demand response, demand-side resources, and energy-efficiency resources	All integration costs	The cost of energy-efficient devices
6. Integration of “smart” appliances and consumer devices.	All integration costs (see above)	Consumer appliances and devices
7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in and hybrid-electric vehicles, and thermal-storage air conditioning.	Bulk power storage devices and high-value distributed storage – such as bulk storage for wind penetration; distributed storage for grid support; customer-side-of-the-meter storage for end-use energy management	Low-value distributed storage
8. Provision to consumers of timely information and control options to enable consumer engagement.	All enabling costs including cost of consumer display devices	None

Table 3-1 (continued)
Technologies Included and Excluded in the Cost Estimates

Technologies	Costs Included in This Analysis	Costs Excluded
10. Identification and lowering of unreasonable or unnecessary barriers to adoption of Smart Grid technologies, practices, and services.	All	None
11. Costs to implement NERC's Critical Infrastructure Protection (CIP) Standards	None	CIP requirements applied to the Distribution System SCADA would incur substantial costs and are excluded here
*It should be noted that some reviewers felt that the cost of new transmission needed to integrate renewables should ultimately be included in estimating the cost of tomorrow's power delivery system.		

One additional cost which could be imposed on some utilities involves conversion to the International Electrotechnology Commission's (IEC) standard for substations communication called IEC 61850. If conversion to IEC 61850 were mandated, legacy systems now utilized by some for both distribution SCADA and communications on the power system would become obsolete. These utilities used a form of Multi-Agent Systems or MAS as a simple format for the exchange of digital information on their power system. For some of these utilities, a mandate to convert to implement IEC 61850 would necessitate replacing their MAS infrastructure, all remote MAS radios and Remote Terminal Units (RTUs) in order to provide the increased bandwidth necessary to support IEC 61850.

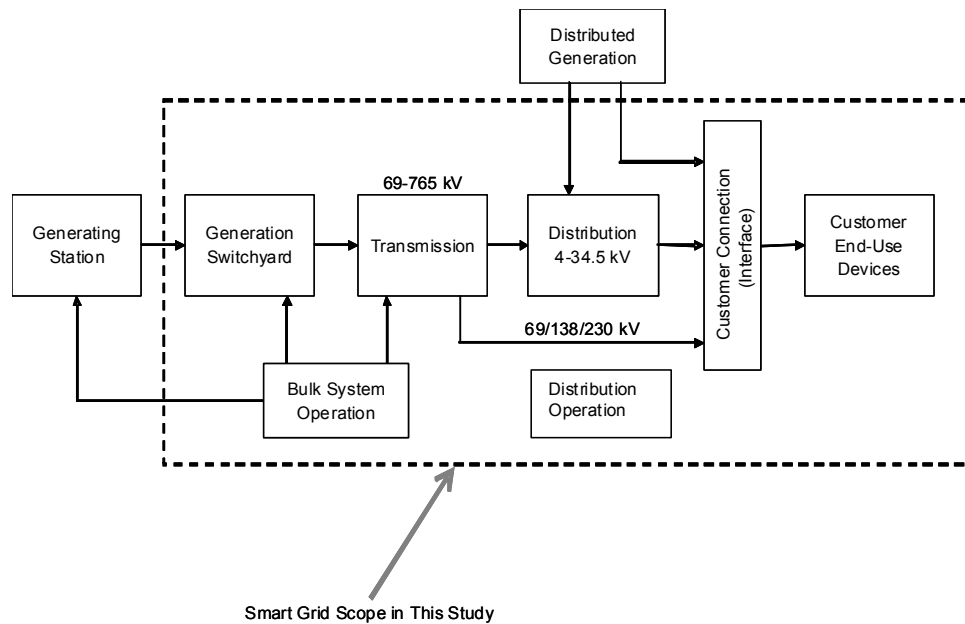


Figure 3-2
Smart Grid Diagram

To conduct a preliminary quantitative estimate of the level of investment needed over the next 20 years to enable the envisioned power delivery system, the project team first decided to treat transmission, distribution, and customer-related costs separately. This is due to fundamental differences in the nature of the transmission and distribution portions of the power delivery system; and uncertainty whether the costs categorized as consumer costs would be borne by utilities, consumers, or third-party service providers. It should be noted that there are, however, substantial areas in which distribution technology enhancements will greatly affect the operation and potentially the configuration of the transmission system. These interactions were not considered in this evaluation. The team also decided to further subdivide the estimating process for transmission and distribution into the following two segments:

- **Load Growth.** Via equipment installation, upgrading, and replacement, transmission and distribution system owners invest in the power delivery system to accommodate new customers (so-called “new connects”) and to meet the increasing energy needs of existing customers as their load grows.
- **Power Delivery System of the Future (“Future PDS”).** The project team estimated the investment needed to develop and deploy advanced technologies needed to realize the vision of the power delivery system (both transmission and distribution) described above.

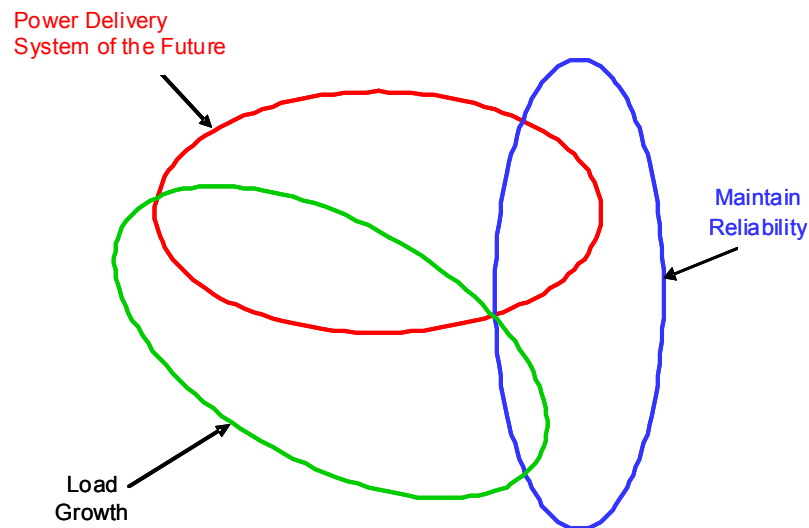
Modernizing an Aging Infrastructure

All components of any infrastructure have limited lives regardless if they are roads, bridges, natural gas transmission, water pipelines or telecommunications. From the moment any given infrastructure is installed or renovated, aging begins.

Accelerated aging resulting in premature or unexpected failure is important to avoid in any of the infrastructures which provide society essential services. Electricity is no exception as failures of components can lead to poor power quality, interruptions or wide-scale blackouts.

In the case of electric power delivery systems, substantial efforts are made to undertake the investments necessary to maintain reliability. Those investments are not included in estimating the cost of the Smart Grid in this study. Transmission and distribution utilities often spend an amount equal to 1 to 2% of their depreciated plant in service on refurbishment so as to maintain reliability. In conducting business as usual, necessary expenditures to accommodate load growth and to maintain reliability will naturally be made with equipment that is compatible with the power delivery system of the future.

Figure 3-3 illustrates how these three cost elements might combine to build the power delivery system of the future. The figure highlights the fact that as utilities make investments to maintain reliability sufficient to accommodate load growth, they are making investments which help build part of the power delivery system of the future.



*Figure 3-3
Illustration of Synergies in the Three Categories of Needed Transmission and Distribution Investment*

Evolving the Smart Grid will mitigate declining reliability caused by aging components on the power delivery system. As Smart Grid components are added to the power delivery system, highlighted as Power Delivery System of the Future in Figure 3-3, and as Load Growth is accommodated as illustrated, the power delivery infrastructure will be strengthened and reliability enhanced. By its nature, the enhanced functionality which the Smart Grid's sensors, communications and computational ability enable will improve O&M, increase reliability and assure that the investments made to maintain reliability are

appropriately targeted at infrastructure components which have the greatest risk of failure. In this study, the project team separated the expenditures necessary to accommodate load growth from the expenditures directly related to the power delivery system of the future, in order to elucidate the true cost of the Future PDS.



Section 4: Power Delivery System of the Future: Benefits (The Benefits of the Smart Grid)

Previous EPRI Study

There have been a number of studies which have estimated some of the benefits of a Smart Grid. Each varies somewhat in their approach and the attributes of the Smart Grid they include. None provides a comprehensive and rigorous analysis of the possible benefits of a fully functional Smart Grid. EPRI intends to conduct such a study, but it is outside the scope of the effort presented in this report.

In 2004, EPRI undertook a study to estimate the cost and value (benefits) of the power delivery system of the future. To do so, it developed a flexible framework.

The fundamental approach that was used in the 2004 study involved the identification of *attributes* of the power system (e.g., cost of energy, capacity, security, quality, reliability, environment, safety, quality of life, and productivity). EPRI then developed the framework to quantitatively estimate the dollar value of improving each of these attributes by a defined amount (i.e., percentage improvement).

Existing, documented data sources were used for this estimation process for each attribute. These sources included the U.S. Energy Information Administration, the U.S. Department of Energy's Policy Office Electricity Modeling System, the Federal Energy Regulatory Commission's transmission constraint study, the U.S. Labor Department's Bureau of Labor Statistics, and many more.

Attributes

Table 4-1 shows the various types of improvements that correspond to each of the attribute types used in the root study. A key aspect of the value estimation process in general is its consideration of improvements to the power delivery system (see the left column of Table 4-1), as well as improvements that consumers directly realize (see the right column of Table 4-1). This was done to

ensure that emerging and foreseen benefits to consumers in the form of a broad range of value-added services addressed in the estimation of value.

Table 4-1

Attributes and Types of Improvements Assumed in the Value Estimation of the Future Power Delivery System (Left: Power Delivery System Improvements; Right: Improvements That Consumers Realize)

Power Delivery (Improvements/ Benefits)	Attributes	Consumer (Improvements/ Benefits)
 O&M Cost Capital Cost of Asset T&D Losses	 Cost of Energy (Net delivered life-cycle cost of energy service)	 End Use Energy Efficiency Capital cost, end user infrastructure O&M, End User Infrastructure Control/Manage Use
Increased Power Flow New Infrastructure Demand Responsive Load	Capacity	Improved power factor. Lower End User Infrastructure cost through economies of scale and system streamlining, expand opportunity for growth
Enhanced Security Self Healing Grid for Quick Recovery	Security	Enhanced Security and ability to continue conducting business and every day functions
Improve Power Quality and enhance equipment operating window	Quality	Improve Power Quality and enhance equipment operating window
Reduce frequency and duration of outages	Reliability & Availability	Enhanced Security Self Healing Grid for Quick Recovery Availability Included
EMF Management Reduction in SF6 (sulfur hexafluoride) emissions Reduction in cleanup costs Reduction in power plant emissions	Environment	Improved Esthetic Value Reduced EMF Industrial Ecology
Safer work environment for utility employees	Safety	Safer work environment for end-use electrical facilities
Value added electric related services	Quality of Life	Comfort Convenience Accessibility
Increase productivity due to efficient operation of the power delivery infrastructure Real GDP	Productivity	Improved consumer productivity Real GDP

The “cost of energy” attribute is the total cost to deliver electricity to customers, including capital costs, O&M costs, and the cost of line losses on the system. Therefore the value of this attribute derives from any system improvement that lowers the direct cost of supplying this electricity. “SQRA” is the sum of the power security, quality, and reliability attributes, because the availability part of SQRA is embedded in the power quality and reliability attributes. The quality of life attribute refers to the integration of access to multiple services, including electricity, the Internet, telephone, cable, and natural gas. This involves integration of the power delivery and knowledge networks into a single intelligent electric power/communications system, which sets the stage for a growing variety of products and services designed around energy and communications.

To quantify the benefit of these improvements for various attributes, the project team developed various “benefit calculator tools.” Figure 4-1 shows the

relationship of these benefit calculator tools, the attributes, and the overall value. Note that science and technology drivers feed generally into the process.

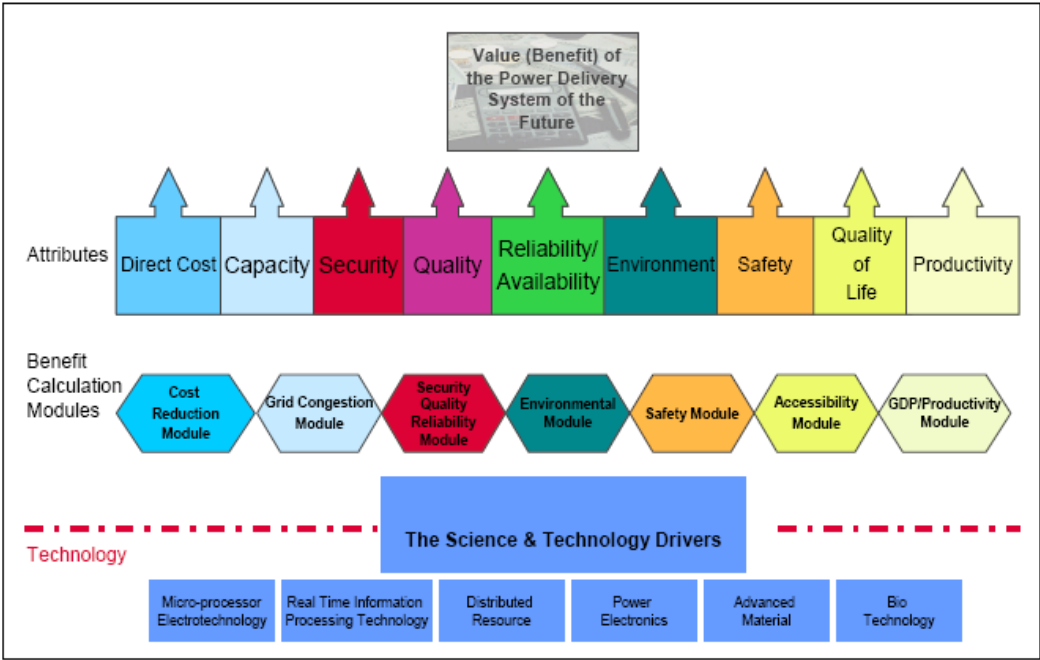


Figure 4-1
Relationship Between Value, Attributes, and Benefit Calculator Tools in the Value Estimation Process

Table 4-2 and Figure 4-1 illustrate the attributes considered in the original estimates of value published in 2004. Table 4-3 summarizes these estimates and escalates them using a chained GDP sequence to 2010 dollars. Table 4-4 lists the major attributes and benefits not included in the original EPRI study.

The increase of benefits using the chained GDP sequence masks the fact that the majority of the overall increase in benefits is from a change in scope of the Smart Grid from a system that can “almost” instantaneously balance supply and demand when the predictability of supply is decreased with the addition of increased amounts of variable renewable resources and the predictability of demand is aggravated with the addition of Plug-in Electric Vehicles, distributed photovoltaics and storage. To rectify this EPRI team analyzed the benefits from Demand Response, PEVs, AMI, Distributed Generation and Storage as shown in Table 2-2. Including these elements has increased the focus of the Smart Grid from operational efficiencies so as to include economic, societal, and energy policy benefits.

The electric power industry is the last industry in the western world to modernize itself through the use of sensors, communications, and computational ability. The combination of these functions allow for a truly interactive power system which can integrate consumer demand with supply interactively.

In addition to the obvious benefits achieved by this enhanced functionality – namely, improved asset utilization, reduced electricity cost, and improved reliability, it is now obvious that other substantive benefits will accrue once the Smart Grid is implemented. Chief among these is the reduction of peak demand, the adoption of electric vehicles, the use of storage, and the increased use of renewable power production.

*Table 4-2
Summary of Benefit Calculations Included in Original EPRI Study*

Benefit Calculations	Attributes
T&D Cost Reduction	Energy efficiency and T&D losses impact on: • Capital cost • O&M Cost • Administrative and general cost
Congestion	• Transmission congestion cost
Security	• Self-healing infrastructure • Mitigating major outages
Power Quality & Reliability/ Availability	• Reliability • Power Quality
Environmental Impact	• SO₂ • CO₂ • NO_x
Safety	• Accidental electrocutions • Building fires caused by electrical infrastructure
Quality of Life	• Access to competing suppliers
GDP/Productivity	• Increase GDP from reduced electricity cost

Table 4-3
Benefit Estimates in 2004 EPRI Study Escalated to 2010 Values

Attribute	Net Present Worth (2004) \$B		Net Present Worth (2010) \$B	
	Low	High	Low	High
Productivity	1	1	1.14	1.14
Safety	11	11	12.54	12.54
Environment	48	48	54.72	54.72
Capacity	49	49	55.86	55.86
Cost	50	50	57	57
Quality	35	57	41.04	64.98
Quality of Life	65	65	74.1	74.1
Security	133	133	151.62	151.62
Reliability	247	390	281.58	444.6
Total	640	804	729.6	916.56

Table 4-4 lists the major attributes and benefits not included in the original EPRI study. Hence, the value of the Smart Grid, even with escalation applied, is substantially understated in Table 4-3.

In order to provide a preliminary estimate of at least the major benefits of a fully functional power delivery system, EPRI has attempted to provide estimates for most of the remaining benefits. These are depicted in Table 4-5 using a framework developed by the U.S. Department of Energy (USDOE) and EPRI (EPRI 1020342). The table includes the attributes and benefits explicitly included in the DOE/EPRI framework as well as other attributes not included.

As summarized in the table, the total benefit of all attributes for the Smart Grid is estimated to be between \$1,294 billion and \$2,028 billion for the period 2010 to 2030. EPRI believes that once all of the attributes and benefits of a Smart Grid are identified and analyzed, estimates of the total benefit will increase even more.

Table 4-4
Major Attributes and Benefits Not Included in Original EPRI Study

Attributes	Benefits
Demand Response	• Reduced need for generation capacity • Reduced demand for electricity
Facilitating Renewables	• Reduced environmental impact of electricity generation
PEVs	• Reduced environmental impact from displaced fossil fuels • Increased system flexibility/ancillary services
Work Force	• Improved utilization of work force
Energy Efficiency	• Generation Capacity deferrals
Enhanced Energy Efficiency (additional energy efficiency)	• Reduced Environmental Impacts
AMI	• AMI-related cost reductions
Distributed Generation	• Facilitating distributed generation
Value-Added Electricity Services	• Comfort and convenience
Synergistic Effects Between Elements	• Compounding between multiple attributes
Storage (various benefits)	• Capacity • O&M • Congestion
Safety	• Personal safety
Transmission O&M	• Ancillary services

Table 4-5

List of Smart Grid Benefits: Based on EPRI/DOE Framework (EPRI 1020342)

Benefit Category	Benefit Sub-Category	Benefit	Included in Original Estimate?	Estimated Value 2010-2030 \$Billion		Reference
				Low	High	
Economic	Improved Asset Utilization	Optimized Generator Operation		—	—	not included
		Deferred Generation Capacity Investments				Appendix A
		Reduced Ancillary Service Cost	X			included below
		Distributed Generation		—	—	not included
		Storage		48	89	Appendix A
		PEVs as Storage & Load Control		11	11	Appendix A
		Energy Efficiency	X			included below
		Demand Response		—	—	not included
		Enhanced Energy Efficiency*		—	—	not included
		Reduced Ancillary Service Cost		—	—	not included
		Reduced Congestion Cost	X			included below
	T&D Capital Savings	Distributed Generation		27	27	Appendix A
		Storage		23	65	Appendix A
		Demand Response		192	242	not included
		Energy Efficiency	X			included below
		Enhanced Energy Efficiency*		1	3	Appendix A
		Deferred Transmission Capacity Investment	X			included below
		Deferred Distribution Capacity Investment	X			included below
		Reduced Equipment Failures	X			included below

Table 4-5 (continued)

List of Smart Grid Benefits: Based on EPRI/DOE Framework (EPRI 1020342)

Benefit Category	Benefit Sub-Category	Benefit	Included in Original Estimate?	Estimated Value 2010-2030 \$Billion		Reference
				Low	High	
Economic	T&D O&M Savings	More Effective Use of Personnel		—	—	not included
		Economic Benefit of Added Personnel		—	—	not included
		Operations Savings from AMI		4	4	Appendix A
		T&D Efficiency	X			included below
		Reduced Distribution Equipment Maintenance Cost	X			included below
		Reduced Distribution Operations Cost	X			included below
	Theft Reduction	Reduced Electricity Theft		—	—	Not included
	Energy Efficiency	Enhanced Energy Efficiency*		0	2	Appendix A
		Electrification (Net Reduced Energy Use)		—	—	Appendix A
		Reduced Electricity Losses	X			included below
		Productivity Increase	X			included below
	Electricity Cost Savings	Reduced Electricity Cost	X			Included below
		Automatic Meter Reading		91	91	Appendix A
		Customer Service Costs (Call Center)		2	2	Appendix A
		Storage		115	199	Appendix A
		Enhanced National Productivity	X			included below
		Reduced Restoration Cost	X			included below
		Speed of Restoration		—	—	not included

Table 4-5 (continued)

List of Smart Grid Benefits: Based on EPRI/DOE Framework (EPRI 1020342)

Benefit Category	Benefit Sub-Category	Benefit	Included in Original Estimate?	Estimated Value 2010-2030 \$Billion		Reference
				Low	High	
		Storage		2	20	Appendix A
		Reduced Sustained Outages	X			included below
		Reduced Major Outages	X			included below
		Accessibility	X			included below
	Power Quality	Reduced Momentary Outages	X			included below
		Reduced Sags and Swells	X			included below
		Storage		1	21	Appendix A
Environmental	Air Emissions	Electrification		21	21	Appendix A
		PEVs		5	123	Appendix A
		Enhanced Energy Efficiency*		1	4	Appendix A
		Storage		10	15	Appendix A
		Facilitate Renewables		10	172	Appendix A
		Reduced CO ₂ Emissions	X			included below
		Reduced SO _x , NO _x and PM-10 Emissions	X			included below

Table 4-5 (continued)

List of Smart Grid Benefits: Based on EPRI/DOE Framework (EPRI 1020342)

Benefit Category	Benefit Sub-Category	Benefit	Included in Original Estimate?	Estimated Value 2010-2030 \$Billion		Reference
				Low	High	
Security	Energy Security	Reduced Imported Oil Usage		—	—	not included
		Personal Security		—	—	not included
		National Security		—	—	not included
		Reduced Wide-Scale Blackouts	X —————→			included below
		Safety	X —————→			included below
Previous EPRI Estimates – All included in original estimate			X	730	917	
Not included in original estimate				564	1,111	
Total				1,294	2,028	
*Enhanced Energy Efficiency includes: Continuous Commissioning of Large Commercial Buildings Direct Feedback on Energy Usage Energy Savings Corresponding to Peak Load Management Energy Savings Corresponding to Enhanced M&V Capability						



Section 5: Transmission Systems and Substations

The high-voltage transmission system is the “backbone” of the power delivery system. It transmits very large amounts of electric energy between regions and sub-regions. Transmission system equipment fails and causes power outages much less frequently than distribution equipment. But when transmission equipment fails, many more customers are affected, and outage costs can be much higher, compared to the impact of a distribution equipment-related outage. This fact, combined with the high cost per mile or per piece of transmission equipment, has historically led to greater attention to transmission system reliability. However, in the last several decades, a variety of factors has led to a significant decrease in investment in transmission system expansion.

Introduction

To estimate the investment needed in the transmission system, a top-down approach was used for the load-growth and correct-deficiencies segments of investment, while a bottom-up approach was used for estimating the elements needed to create a Smart Grid. In the U.S., according to EEI, there are now more than 200,000 miles of high-voltage transmission lines greater than 230 kV. An earlier study by DOE, entitled the *National Transmission Grid Study, 2002*, showed a total of 187,000 miles, broken down by the voltage levels shown in Table 5-1.

The total cost for enhancing transmission system and substation performance to the level of a Smart Grid is estimated between \$56 and \$64 billion, as summarized in this section. The cost includes several categories of technology whose functionality overlaps significantly between the transmission system and substations as well as some elements of the distribution system described later, as well as enterprise level functions, such as cyber security and back office systems.

Table 5-1
Transmission Line Miles

Voltage (kV)	Miles
230 AC	85,048
345 AC	59,767
500 AC	32,870
765 AC	4,715
250-500 DC	3,307
Total Miles	184,707

In general, monitoring of transmission assets is more cost-effective and beneficial than any other asset class (EPRI 1016055). Although transmission lines are one of the critical core backbone elements of the power grid, thousands of miles are unattended and not monitored in any way. Transmission lines have seasonal ratings that need to be considered by operations and planning. For the most part, there is little if any real-time monitoring other than at substations that provide operators with loading information.

Transmission investment trended downward for more than two decades, declining from \$4.8 billion in 1975 to \$2.25 billion in 1997, then leveled off before beginning to climb again. It reached roughly \$5 billion in 2000 and is expected to reach nearly \$11 billion in 2010. Smart Grid functionality should help to increase the value of future transmission investment over and the expansion needed to meet load growth.

The number of substations is one of the basic metrics upon which investment costs were determined. There are an estimated 70,000 substations in the U.S. that reduce voltage between the bulk transmission system and the distribution feeder system, and serve as critical hubs in the control and protection of the electricity grid. This figure was derived from FERC data that shows investor-owned utilities (IOUs) operate a total of 40,619 substations at voltage levels ranging from just above 1 kV to 765 kV. Since IOUs represent roughly 70% of all U.S. customers, the number of existing substations was thus calculated to be 58,027 ($40,619/.7 = 58,027$).

As elucidated in Chapter 3, load was estimated in the study to grow at a rate of 0.68%/year. Compounded over the 20-year period of the study (2010-2030), this would imply an additional 8,423 substations will be required by 2030. Accordingly, the base figure used throughout this report for substations is 58,027 which could potentially be upgraded and 8,423 which will be new. In addition to this base, another 700 substations will be required by 2030 to handle renewable generation.

Other key benchmarks used in the analysis include an estimate of 8 feeders/substation serving lower-voltage customers downstream. Thus, there are 464,216 feeders that are eligible to be upgraded with intelligent electronic devices

for a fully functioning Smart Grid. In addition, there are 67,384 new feeders to be added to accommodate load growth. Segments of the feeders that can be isolated electrically in case of faults and/or reconfiguration are called “pods,” and for purposes of the Smart Grid, the analysis team used roughly 4 pods/feeder, yielding more than 2,260,000 isolatable pods for purposes of monitoring and control.

Table 5-2 lists these assumptions.

Table 5-2
Number of Substations and Feeders

Substations	Number
Existing substations	58,027
New substations to accommodate load growth (2030)	8,423
New substations to accommodate renewables (2030)	700
<u>Distribution</u>	
Number of existing feeders	464,216
New feeders to accommodate load growth (2030)	67,384

An underlying assumption in the report is that the digital devices to be deployed in the Smart Grid will comply with the International Electrotechnology Commission (IEC) Standard 61850 (IEC 61850). That standard applies to substation automation and protection, distribution automation, distributed energy resources, hydro generation, SCADA to field devices, and applies to protective relays, SCADA Master, DER, PQ meters, fault recorders and other applications.

Cost Components for the Smart Grid: Transmission Systems and Substations

The core components of cost for the transmission and substation portion of the Smart Grid are as follow:

- Transmission line sensors including dynamic thermal circuit rating
- Storage for bulk transmission wholesale services
- FACTS devices and HVDC terminals
- Short circuit current limiters
- Communications infrastructure to support transmission lines and substations
- Core substation infrastructure for IT
- Cyber-security
- Intelligent electronic devices (IEDs)
- Phasor measurement technology for wide area monitoring

- Enterprise back-office system, including GIS, outage management and distribution management
- Other system improvements assumed to evolve naturally include:
 - Faster than real-time simulation
 - Improved load modeling and forecasting tools
 - Probabilistic vulnerability assessment
 - Enhanced visualization

Substation upgrades will enable a number of new functions including, but not limited to:

- Improved emergency operations
- Substation automation
- Reliability-centered and predictive maintenance

Dynamic Thermal Circuit Rating (DTCR)

Dynamic rating and real-time monitoring of transmission lines are becoming important tools to maintain system reliability while optimizing power flows. Dynamic ratings can be considered a low-cost alternative for increased transmission capacity. Dynamic ratings are typically 5 to 15% higher than conventional static ratings. Application of dynamic ratings can benefit system operation in several ways, in particular by increasing power flow through the existing transmission corridors with minimal investments.

Dynamic rating increases the functionality of the Smart Grid because it involves the monitoring of real-time system data that can be used in various applications:

- Real-time monitors yield a continuous flow of data to system operations – line sag, tension or both, wind speed, conductor temperature, etc. – traditionally not available to operators.
- Monitored data can be processed to spot trends and patterns.
- Real-time monitored data may be turned into useful operator predictive intelligence (e.g., critical temperature and percent load reduction needed in real time).

The New York Power Authority (NYPA) has engaged with EPRI in a demonstration project that will evaluate the instrumentation and dynamic thermal ratings for overhead transmission lines. An area of possible application for DTCR is the growing penetration of wind generation; when turbines are operating, one expects higher dynamic ratings because of increased wind speed. The project will use EPRI's DTCR software, which uses real-time or historical weather and electrical load data to calculate dynamic ratings for overhead lines in real time based on actual load and weather conditions that generally are accessed through the utility's SCADA/EMS system.

The study team assumed that AC transmission lines rated 115 kV to 230 kV in the U.S. are most susceptible to being thermally limited. They considered lines rated 345 kV and above are more likely voltage-limited. Albeit, there may be a few lines rated at these higher voltages that are thermally limited – they would be an exception and not the rule. Furthermore, of the lines which are potentially thermally limited, only 50% actually are. There are 85,048 miles of lines at 230 kV. To dynamically rate all 85,048 miles would require one unit per 7.5 miles or 11,340 units. The cost of DTCR deployed in quantity is estimated to be \$20,000 initially, declining to \$10,000.

It should be noted that the above calculation does not include any transmission lines at voltages lower than 230 kV, e.g., 115, 138 and 161 kV. It is expected that these transmission lines will benefit from DTCR.

Table 5-3
Cost of Dynamic Thermal Circuit Rating

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low– High \$M
Dynamic-Thermal Circuit Rating	11,340	Units/7.5 miles DTCR line	100	10,000	20,000	113.4– 226.8

Sensors and Intelligent Electronic Devices

The Smart Grid will require a more diverse and wider array of sensors and other Intelligent Electronic Devices (IEDs) throughout the power system to monitor conditions in real time. In particular, sensors in transmission corridors and in substations can address multiple applications:

- **Safety:** The application of sensors for transmission line or substation components will allow for the monitoring and communication of equipment conditions. Information that a transmission line or substation component is in imminent risk of failure will enable actions to be taken to address the safety of utility personnel.
- **Workforce Deployment:** If the condition of a component or system is known to be at risk, personnel can be deployed to prevent an outage.
- **Condition-Based Maintenance:** Knowledge of component condition enables maintenance actions to be initiated at appropriate times rather than relying on interval-based maintenance.
- **Asset Management:** Improved knowledge of the condition of equipment and stresses that they have been subjected to will allow managers to better manage the assets. Sensor data used together with historic performance

information, failure databases and operational data allows better allocation of resources.

- **Increased Asset Utilization:** The rating of transmission components is influenced by a range of factors such as ambient weather conditions, loading history and component configuration. In order to address this complexity, static ratings are usually based on conservative assumptions of these factors. Higher dynamic ratings can be achieved with more precise, real-time knowledge of the asset's condition.
- **Forensic and Diagnostic Analysis:** After an event occurs, there is limited information to understand the root cause. Sensors allow the capture of pertinent information in real time for a more rigorous analysis.
- **Probabilistic Risk Assessment:** Increased utilization of the grid is possible if contingency analyses are performed using a probabilistic, rather than deterministic, methods. To use probabilistic methods, knowledge of the condition of components and the risks they pose are needed

The transmission system of the future will utilize a synergistic concept for the instrumentation of electric power utility towers with sensor technology designed to increase the efficiency, reliability, safety, and security of electric power transmission. The system concept is fueled by a list of sensing needs illustrated in Figure 5-1 (EPRI 1016921). This system scope is limited to transmission line applications (i.e., 69 kV and above), not distribution, with the focus on steel lattice and pole structures, not wooden.

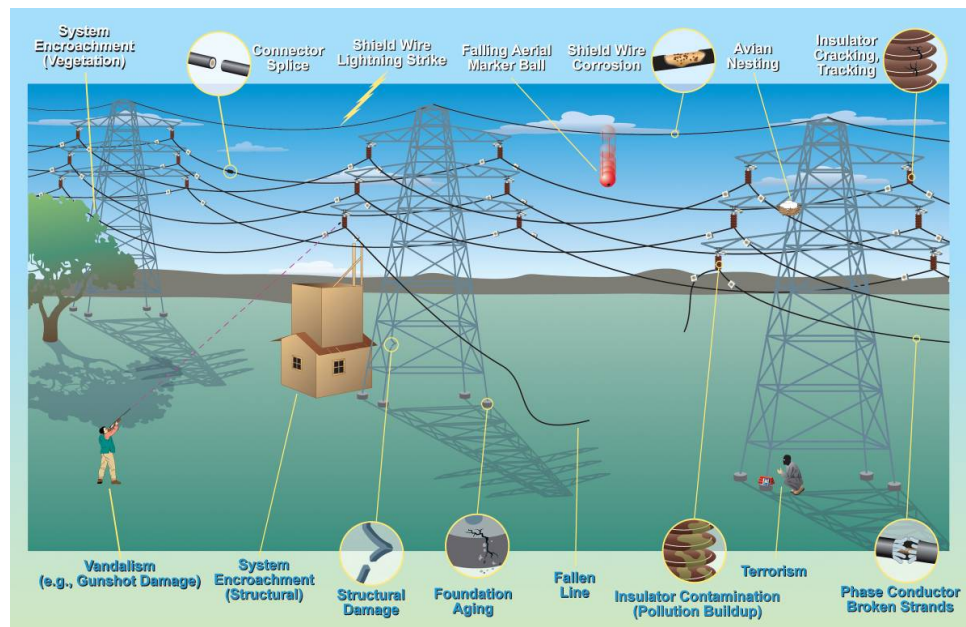


Figure 5-1
Illustration of Sensor Needs for Transmission Lines and Towers (EPRI 1016921)

In this concept, the addition of wiring to interconnect and/or power distributed sensors is not viable because of electromagnetic susceptibility concerns and labor

intensive installation. Consequently, sensor concepts will rely on wireless and/or fiber optic technology.

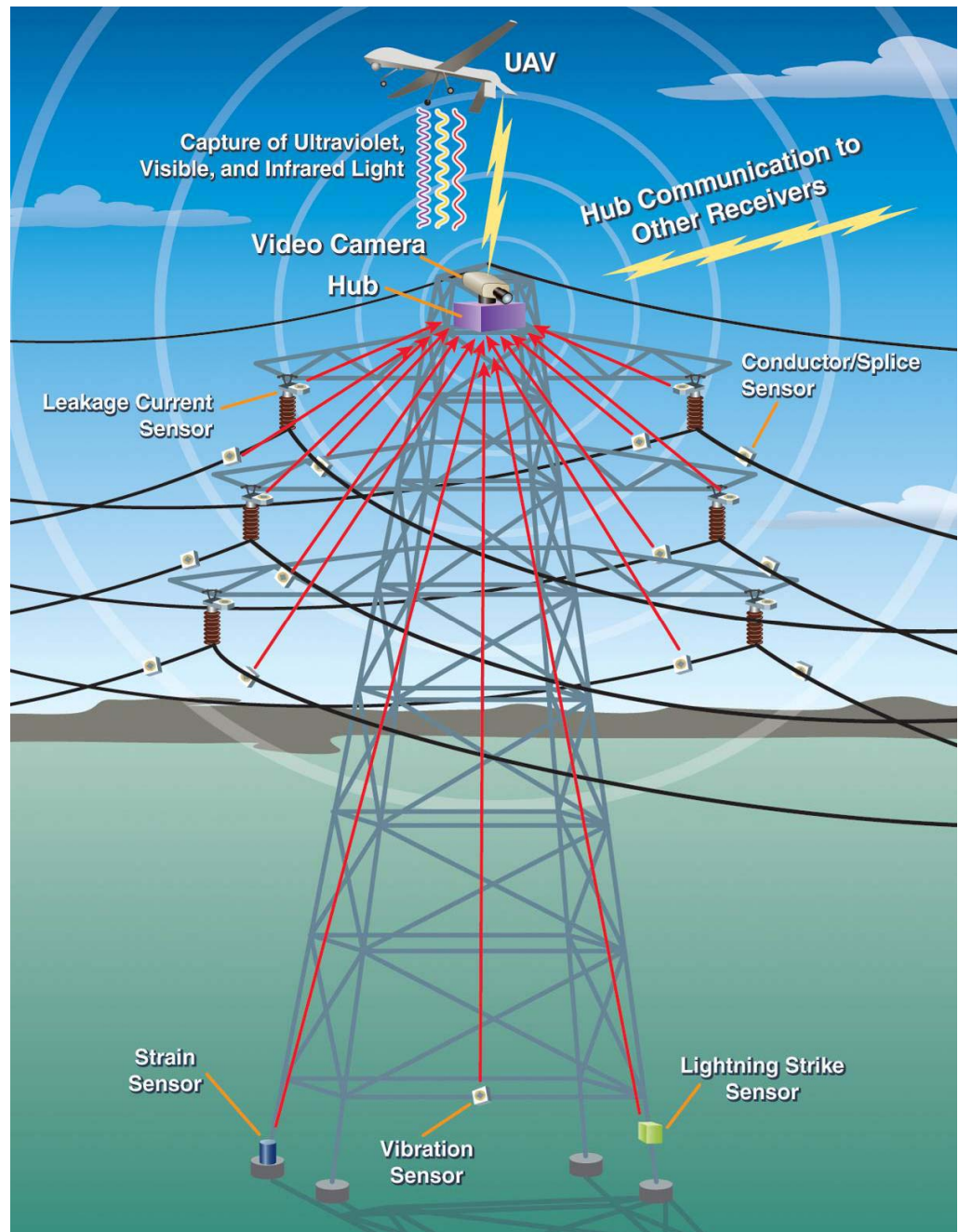


Figure 5-2
Image Showing a Single Structure Illustrating Some of the Concepts (EPRI 1016921)

Figures 5-1 and 5-2 depict some of the high-level concepts that are listed below:

- Sensors distributed on transmission structures and /or conductors.

- Sensors that may or may not communicate with the “hub” installed on the structure – either wireless or wired.
- Sensor information is collected, stored and analyzed in a “central database” which is part of the utility’s current data management system. The data is collected /communicated from the sensors /hubs to the central database using one of the following methods:
 - Wirelessly back to the central database from the individual structure hub, e.g. RF directly, via satellite or cell phone network.
 - Collected using a vehicle traveling the length of the line. The data from the collection vehicle is transferred during or after the inspection. The following is a list of possible data collection vehicles:
 - Unmanned Airborne Vehicle (UAV)
 - Manned Aerial Vehicle
 - Line Crawler Robot
 - If the vehicle data collection approach is utilized:
 - The vehicle may collect the data wirelessly directly from the sensors (possibly excluding the need for a structure “hub”).
 - The vehicle may also have sensors aboard recording data during the collection process, (e.g. video, UV, IR, still images)

These concepts are discussed in detail in the following sections.

There are a number of possible sensors to address each of these applications. Table 5-4 below elucidates the range of sensor needs. The study team assumed that by 2030 one-half of all substations would have installed an advanced sensors package on the transmission system, costing roughly \$50,000-100,000/substation. The total Smart Grid investment for sensors approaches \$1.5 to 2.9 billion. In addition, 100% of new substations built to accommodate load growth would incorporate a suite of sensors at a cost ranging between \$421 to 842 million.

Table 5-4
Sensor Needs

	Item	Cause	Result	Update Interval	Probability	Consequence	Sensing Technologies
1	System Tampering	Terrorism	Tower/line down	Real-time	Low	High	Vibration, Acoustic, E-Field, Optical
2	System Encroachment	Man-made	Safety hazard, Less reliable	3-12 mo	High	Med	Optical, Satellite, Proximity, Vibration, E-Field
3	System Encroachment	Vegetation	Flashover, Fire	3 mo	High	High	Optical, Satellite, LIDAR, Line-of-Sight, Proximity
4	System Encroachment	Avian Nesting, Waste	Flashover	6-12 mo	High	High	Optical, Vibration, Leakage Current, Proximity, E-Field
5	Shield Wire	Corrosion	Flashover, Outage	3-6 years	Med	High	Optical, IR Spectroscopy, Eddy Current, MSS
6	Shield Wire	Lightning	Flashover, Outage	1 year	Med	High	Optical, IR Spectroscopy, Eddy Current, MSS, Lightning Detection, Vibration
7	Insulator (Polymer)	Age, Material Failure	Outage	6 years	Med	High	Optical, Vibration, RFI, UV, IR
8	Insulator (Ceramic)	Age, Material Failure	Outage	12 years	Low	High	Optical, Vibration, RFI, UV, IR
9	Insulator	Contamination	Flashover	3 mo	Med	Med	Optical, RFI, UV, IR, Leakage Current
10	Insulator	Gun Shot	Outage	Real-time, 3 mo	Med	High	Optical, Vibration, RFI, UV, IR, Acoustic

Table 5-4 (continued)
Sensor Needs

	Item	Cause	Result	Update Interval	Probability	Consequence	Sensing Technologies
11	Phase Conductor	External strands broke	Line Down, Fire	1 year	Low	High	Optical, Vibration, RFI, UV, IR
12	Phase Conductor	Internal strands broke	Line Down, Fire	1 year	Low	High	E-MAT, MSS, Electromagnetic
13	Phase Conductor	Corrosion of steel core	Line Down, Fire	1 year	Low	High	E-MAT, MSS, Electromagnetic, IR Spectroscopy, Optical
14	Connector Splice	Workmanship, thermal cycling, age	Line Down, Fire	1 year	Med	High	Direct Contact Temperature, IR Temperature, Ohmmeter, RFI, E-MAT, MSS
15	Hardware	Age	Line Down, Fire	6 years	Low	High	Optical, IR Spectroscopy
16	Phase Spacer	Age, galloping event	Line Down, Fire	6 years	Low	Med	Optical, UV, RFI
17	Aerial Marker Ball	Vibration Damage, Age	Safety concerns	1 year	Low	Med	Optical, UV, RFI
18	Structure (Steel Lattice)	Corrosion	Reliability Concerns	10 years	Med	Med	Optical, IR Spectroscopy
19	Structure (Steel Lattice)	Bent, damaged members	Reliability Concerns	1 year	Med	Med	Optical, Strain, Position, Tilt
20	Structure (Steel Pole)	Corrosion, age	Reliability Concerns	10 years	Med	Med	Optical, IR Spectroscopy

Table 5-4 (continued)
Sensor Needs

	Item	Cause	Result	Update Interval	Probability	Consequence	Sensing Technologies
21	Structure (Steel Pole)	Internal Deterioration	Reliability Concerns	1 year	Med	Med	Optical, MSS, Ultrasonics
22	Foundation (Grillage)	Age, corrosion	Reliability Concerns	10 years	High	High	Excavation, MSS, Radar, GPR Imaging, Half Cell, Voltage Potential
23	Foundation (Anchor Bolt)	Age, corrosion	Reliability Concerns	10 years	Low	High	Optical, Ultrasonics, E-MAT, Vibration
24	Foundation (Preform)	Age, corrosion	Reliability Concerns	10 years	Med	High	Optical, Ultrasonics, E-MAT, Vibration
25	Foundation (Stub Angles)	Age. Corrosion	Reliability Concerns	10 years	Low	High	Optical, Ultrasonics, E-MAT, Vibration
26	Foundation (Direct Embedment)	Age, corrosion	Reliability Concerns	10 years	High	High	Excavation, MSS, Half Cell, Voltage Potential
27	Foundation (Anchor Rods, Screw-In)	Age, corrosion	Reliability Concerns	10 years	High	High	Excavation, MSS, Half Cell, Voltage Potential, Ultrasonics
28	Grounding	Age, corrosion, tampering	Reliability, Lightning, Safety concerns	6 years	Med	Med	AC impedance, DC resistance, Impulse
29	TLSA (Transmission Line Surge Arrestor)	Lightning Strikes, age	Reliability, Lightning Concerns	1 year	Med	Med	Optical, IR, Leakage Current, Lightning Strike Counter

The sensor system architecture is comprised of sensors that acquire diagnostic data from components of interest and from communications hubs that collect the sensor data and relay it to a central repository. Sensors may be directly attached to the item being monitored, or may be remotely located such as in the case of a camera. Communications hubs may be mounted on or near towers or may be located on a wide variety of mobile platforms, such as manned airplanes or unmanned line crawlers or UAVs. Sensors and hubs may operate and be polled periodically (e.g., at intervals of minutes, hours, days) or continuously monitored (e.g., a real-time alarm) depending on the application. In any case, sensors communicate their results via hubs to a central repository. Figure 5-3 illustrates the architecture and flow of data.

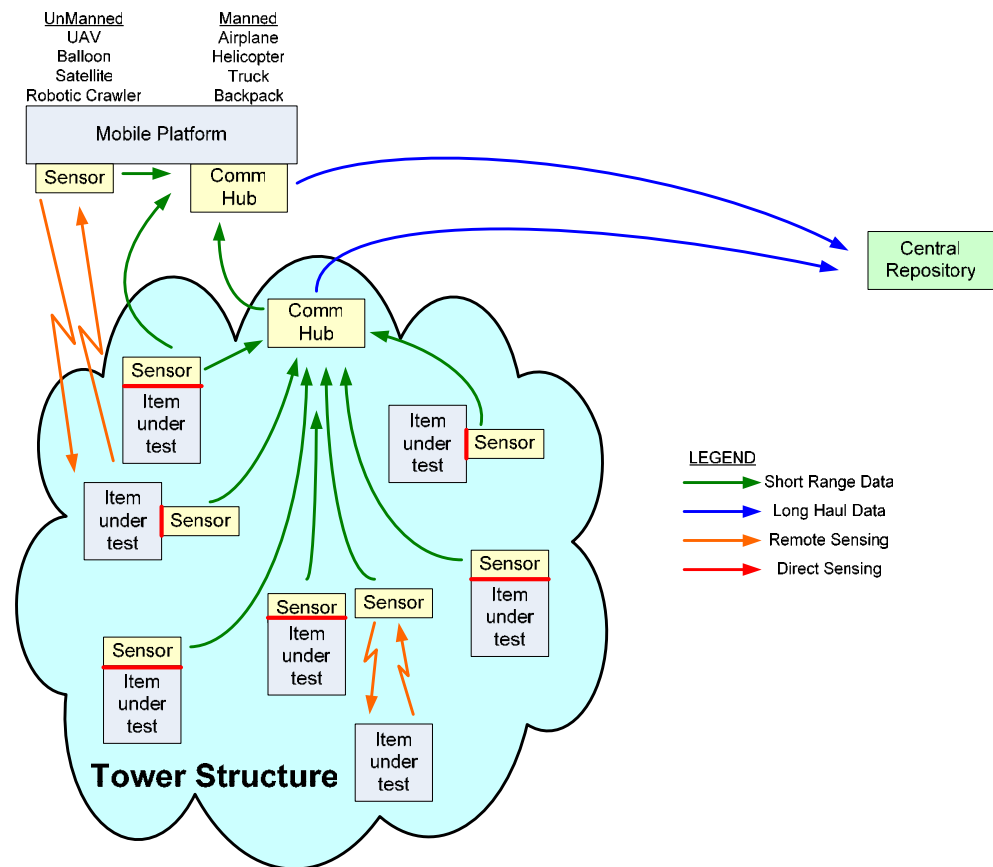


Figure 5-3
Sensor System Architecture [EPRI 1016921]

Table 5-5
Cost of Sensors

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Transmission Line Sensors	58,027	Number of existing substations	50*	50,000	100,000	1,451-2,901
Transmission Line Sensors	8,423	Number of new substations	100	50,000	100,000	421-842
*Assumes 50% of substations will have sensors listed in Table 5-4 partially deployed.						

Examples of Transmission Line Sensors



Figure 5-4
RF Conductor temperature and current sensor, offering power harvesting, live working install, and low cost. Cost is an order of magnitude lower than that of other available technologies.



*Figure 5-5
Clamp-on RF leakage current sensor for transmission line applications installed on
a 115-kV composite insulator.*



Figure 5-6

An RF leakage current sensor installed on a post insulator in a substation. It also shows dry band arcing (the discharge activity due to contamination and wetting that causes the leakage currents) captured during a contamination event. The sensor recorded the event



Figure 5-7

Antenna array installed on a portable trailer deployed in a 161-kV substation.



*Figure 5-8
A solar-powered tank-top temperature sensor installed on a transformer.*



*Figure 5-9
An MIS sensor for measuring acetylene gas levels in oil. The use of MIS gas-in-oil sensors can increase the number of transformers monitored due to their lower cost.*



Figure 5-10
Conductor temperature sensors installed on a steel-reinforced aluminum cable (ACSR) conductor. The sensor communicates using a cell phone modem.

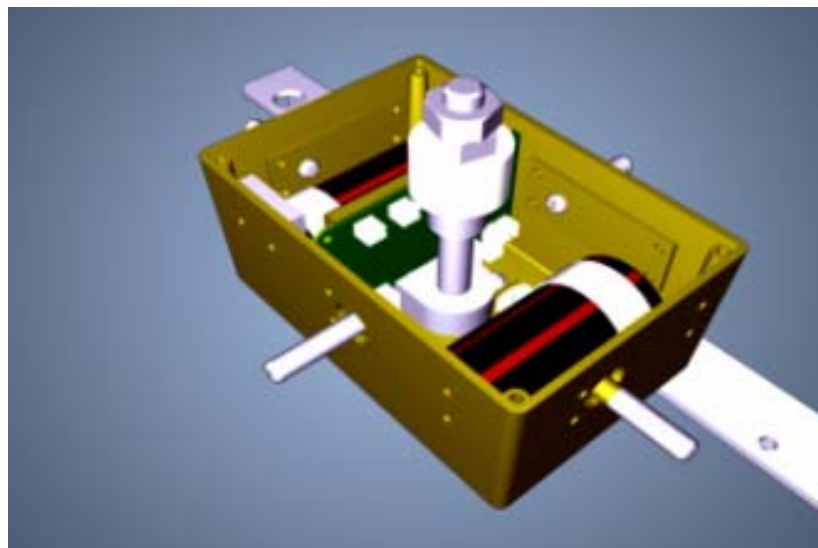


Figure 5-11
Inside the housing of a leakage current monitoring sensor utilized on post-type insulators. The two lithium polymer batteries utilized to power the sensor for 14 years.

Short-Circuit Current Limiters (SCCL)

The short-circuit current limiter (SCCL) is a technology that can be applied to utility power delivery systems to address the growing problems associated with fault currents. The present utility power delivery infrastructure is approaching its

maximum capacity and yet demand continues to grow, leading in turn to increases in generation. The strain to deliver the increased energy demand results in a higher level of fault currents. The power-electronics-based SCCL is designed to work with the present utility system to address this problem. It detects a fault current and acts quickly to insert an impedance into the circuit to limit the fault current to a level acceptable for normal operation of the existing protection systems.

The SCCL incorporates advanced Super GTO (SGTO) devices for a higher-performing and more compact system that incorporates the most advanced control, processing, and communication components. This enables it to function as a key part of the Smart Grid.

The study team expects installation of the SCCL to begin in ten years and to be phased in slowly, beginning in 2020. From 2020, penetration will rise to 2% of transmission substations by 2030. The installation cost will be about \$500,000 for SCCL at transmission substations, and about \$50,000 at distribution substations. Total installed cost for transmission circuit current limiters through 2030 is estimated at \$2.03 billion.

Table 5-6
Cost of Transmission Short Circuit Current Limiters

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Transmission Short-Circuit Current Limiters	58,027	Number of substations	2	500,000	500,000	580.3-580.3

Flexible AC Transmission System (FACTS)

There are a number of flexible AC transmission (FACTS) technologies which are critical to the Smart Grid. These all incorporate power electronics and can be applied to the transmission system. These include both the control and operation of the power system and applications that will extend eventually to transformers themselves.

FACTS devices can be used for power flow control, loop flow control, load sharing among parallel corridors, voltage regulation, enhancement of transient stability, and mitigation of system oscillations. FACTS devices include the thyristor controlled series capacitor (TCSC), thyristor controlled phase angle regulator (TCPAR), static condenser (STATCON), and the unified power flow controller (UPFC). AEP installed the first UPFC at its Inez substation in eastern Kentucky in 1998 (EPRI 1010633).

FACTS is a concept invented by EPRI in the 1980s, for which EPRI developed several patents licensed to Siemens. It involves the injection of a variable-voltage source, which adjusts the power flow across a transmission line, resulting in variable voltage, impedance, and phase angle. Six successful major FACTS installations were demonstrated, each with several key features. For example, one installation at the New York Power Authority's Marcy Substation resulted in the ability to increase power-transfer capacity into New York City by 200 MW, resulting in substantial savings. However, these FACTS devices did not spawn an anticipated revolution in the control of power flow, as was expected. They were plagued by three technical problems, the combination of which made FACTS 20% more costly than "conventional" solutions. These technical problems included the cost and performance of the control systems within the devices; the performance of the systems used to cool the electronics; and the cost and performance of the power-electronic devices themselves. As of now, the first two of these issues have been resolved, and with the successful demonstration of advanced power electronics, there is relative certainty that the industry is poised for a rebirth of FACTS. This is especially important with the introduction of increasing amounts of variable generation – like wind and solar – located far from load pockets.

The advantages of FACTS technology are as follows:

- Increases the amount of power that can be imported over existing transmission lines.
- Provides dynamic reactive power support and voltage control.
- Reduces the need for construction of new transmission lines, capacitors, reactors, etc which mitigate environmental and regulatory concerns, and improves aesthetics by reducing the need for construction of new facilities.
- Improves system stability.
- Controls real and reactive power flow.
- Mitigates potential Sub-Synchronous Resonance problems.

FACTS for HVDC – The backbone of HVDC transmission is a FACTS device which is the converter station that converts AC to DC for transmission and then converts DC back to AC at the other end of the line. Power electronics do the heavy lifting in these applications. In the 400- to 1000-MW range, second-generation IGBT power-electronic devices are used, while in the 1000-MW and above range, older technologies are used (namely, thyristors). As load growth increases and the use of renewable power generation located far from the load pocket becomes the norm, there will be increased demand for DC technology. DC technology may be the only effective means of increasing power flow on an existing corridor that was originally built for AC transmission.

FACTS for Controlling Reactive Power – TCSCs are a derivation of the FACTS technology that uses power electronics to inject capacitance into the power system to improve power flow by controlling reactive power. There are roughly 100 TCSCs installed in the U.S., primarily in the west. Eastern utilities

have been reluctant to take advantage of this technology due to concerns about sub-synchronous resonance. Further development of thyristor control can dampen those oscillations.

FACTS for Electronic Transformers – Power-electronic transformers will eventually become part of the transmission system. Existing mechanical switching is accomplished within about 6 AC cycles. This is rapid enough for most applications. However, there is a need for a power-electronic device that could reduce short-circuit currents and then act as power-electronic circuit breaker at the same time. The potential maximum for short-circuit currents is growing so as to exceed the maximum capacity of today’s breaker fleet. A distribution device to limit short-circuit currents using power electronics has been demonstrated. Further development could allow this device to scale up to high voltage and, coincidentally, act as a fast-switching power-electronic breaker. This device would have the added benefit of eliminating the use of SF6. Considerable effort has been expended in the development of distribution transformers based on power electronics. Using power electronics in transformers can eliminate the majority of the inductance and, along with it, all of the oil used as coolant, resulting in a substantial reduction in the losses. In addition, it offers a great deal more flexibility in voltage control. The potential to scale up the distribution version of this transformer is promising. Further advancement in power electronics will be needed to realize for this transmission application.

Power Electronic Devices for Mitigating Geomagnetically-Induced Currents – Geomagnetically-induced currents can cause serious problems to high-voltage equipment and promote blackouts. The future application of power electronics to be applied to the grounded neutral on substation transformers could neutralize these currents. Further development is needed to realize this technology in the 2020 to 2030 time frame.

*Table 5-7
DC Lines and Terminals Known to be Under Consideration*

Renewable Studies	No. Lines	Type
EWITS	10	800 kV DC lines
WWIS	1	600 kV DC lines
HPX	2	500 kV DC lines
Santa Fe	1	500 kV DC lines
Clean Line	1	500 kV DC lines
Total	15	Lines or 30 HVDC Terminals

Table 5-8

Estimated Additional FACTS Devices Needed by 2030

FACTS Devices	Number of Units	Cost/Unit		Total Costs	
		Low \$	High \$	Low \$	High \$
STATCON & UPFC	20	35,000,000	45,000,000	700,000,000	900,000,000
TCSC	100	10,000,000	12,000,000	1,000,000,000	1,200,000,000
HVDC Terminals	60	22,500,000	27,500,000	1,350,000,000	1,650,000,000
Power Electronic Transformers	25	40,000,000	40,000,000	1,000,000,000	1,000,000,000
Geomagnetic Controllers	25	5,000,000	7,000,000	125,000,000	175,000,000
Total FACTS Cost				4,175,000,000	4,925,000,000

Storage

Bulk storage is one of the major limitations in today's "just in time" electricity delivery system and one of the great opportunities for Smart Grid development in the future. Only about 2.5% of total electricity in the U.S. is now provided through energy storage, nearly all of it from pumped hydroelectric facilities used for load shifting, frequency control, and spinning reserve. System balancing is provided by PH, combustion turbines, and the cycling of coal power systems. (In contrast, some 10% of the electricity produced in Europe is cycled through a storage facility of some kind, and Japan stores 15% of the electricity it produces.) Deployment and policy have been instrumental in long-term resource planning and management.

Storage is essential for electricity consumers where power quality and reliability is critical, such as at airports, broadcasting operations, hospitals, financial services, data centers, telecommunications, and many finely tuned industrial processes. Such operations frequently install energy storage as part of an uninterruptible power supply. In the future, storage—as both an end user and electric utility energy management resource—will become possible due to a confluence of high TOU rates, dynamic pricing, and lower cost energy storage systems.

Compressed air energy storage (CAES), pumped hydro, and advanced lead-acid batteries are the primary options for utilities pursuing bulk storage for T&D grid support and system and renewables integration. Table 5-9 shows the cost for CAES running from \$810-1045/kW, whereas lead-acid batteries typically exceeds \$2000/kW (EPRI 1017813).

Table 5-9
Highest Value Electrical Storage Technologies

Highest Value Storage Market	kW	Best Technology Fit	Cost/kW
Wholesale Services Without Regulation	5,800,000	CAES	\$810-1045
Wholesale Services With Regulation	2,800,000	CAES	\$810-1045
Home Backup	2.8	Lead-Acid	\$2200
Industrial Power Quality & Reliability	1.8	Advanced Lead-Acid	\$2300-2400
Transportable Storage Systems (for Distribution Deferral)	1.7	Advanced Lead-Acid	\$2180-2900

Note: Li-ion systems may, in the long run, be a potentially low-cost option for grid support. This maybe driven by the large-scale manufacturing underway for the automotive maker. These may be the most compelling for energy durations under four hours with one to three hours being the sweet spot.

The study team estimated the installation of 5,800,000 kW of CAES storage capacity for wholesale services in areas without regulation, and 2,800,000 kW of capacity for wholesale services with regulation. The total investment cost over the next 20 years is estimated at \$4.7 billion to \$6.1 billion, as shown in Table 5-10.

Table 5-10
Cost of Storage Technology

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Storage for Bulk Transmission Wholesale Services Without Regulation	5,800,000	kW	100	810	1045	4,698-6,061
Storage for Bulk Transmission Wholesale Services With Regulation	2,800,000	kW	100	810	1045	2,268-2,926

Recently, it was announced that several Li-ion systems are going in to provide fast regulation services. It is speculated that their costs may be as low as \$1,200 per kW. These technologies could provide frequency regulation at lower costs and less lumpy investments than CAES. However, CAES is needed to avoid wind curtailment under high penetration wind scenarios.

Communications and IT Infrastructure for Transmission and Substations

Smart substations require new infrastructure capable of supporting the higher level of information monitoring, analysis, and control required for Smart Grid operations, as well as the communication infrastructure to support full integration of upstream and downstream operations.

The substation of the future will require a wide-area network interface to receive and respond to data from an extensive array of transmission line sensors, dynamic-thermal circuit ratings, and strategically placed phasor measurement units. The smart substation must be able to integrate variable power flows from renewable energy systems in real time, and maintain a historical record or have access to a historical record of equipment performance. Combined with real-time monitoring of equipment, the smart substation will facilitate reliability-centered and predictive maintenance.

The core and distributed IT infrastructure will be able to coordinate the flow of intelligence from critical equipment, such as self-diagnosing transformers, with downstream operations, and be able to differentiate normal faults from security breaches. It will be able to distill and convey critical performance data and maintenance issues to back office systems.

The smart substation will build upon the existing platform. There is already a significant installed base of sensors at substations, but there is still limited bandwidth connecting the substation to the enterprise. Historically, the communications channel to the substation was justified as part of the installation of the energy management system (EMS) and supervisory control and data acquisition (SCADA) systems. A key consideration for the future is that these legacy systems have limited bandwidth.

The study team estimates a cost of \$50,000-\$75,000 per substation to achieve the optimal performance level required for the Smart Grid. Substation upgrades will phase in slowly over the next 20 years, reaching an 80% penetration level of all existing substations by 2030. This suggests a cumulative investment between \$2.9 billion and \$4.2 billion by 2030. All new substations will incorporate communications and IT infrastructure at the time of construction.

Table 5-11

Cost of Communications and IT Infrastructure for Transmission and Substations

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Core Substation Infrastructure for IT: Smart Substations	58,027	Number of existing substations	80	50,000	75,000	2,321-3,481
Communications Infrastructure to Support Transmission Lines & Substations	58,027	Number of existing substations	80	14,400	14,400	668.5-668.5
Total IT & Communications Infrastructure for Existing Substations						2,989.5-4,149.5
Core Substation Infrastructure for IT: Smart Substations	8,423	Number of new substations	100	50,000	75,000	421-632

Table 5-11 (continued)

Cost of Communications and IT Infrastructure for Transmission and Substations

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Communication s Infrastructure to Support Transmission Lines & Substations	8,423	Number of new substations	100	14,400	14,400	121-121
Total IT & Communication s Infrastructure for New Substations						542-753

Intelligent Electronic Devices (IEDs)

Intelligent Electronic Devices (IEDs) encompass a wide array of microprocessor-based controllers of power system equipment, such as circuit breakers, transformers, and capacitor banks. IEDs receive data from sensors and power equipment, and can issue control commands, such as tripping circuit breakers if they sense voltage, current, or frequency anomalies, or raise/lower voltage levels in order to maintain the desired level. Common types of IEDs include protective relaying devices, load tap changer controllers, circuit breaker controllers, capacitor bank switches, recloser controllers, voltage regulators, network protectors, relays etc.

With available microprocessor technology, a single IED unit can now perform multiple protective and control functions, whereas before microprocessors a unit could only perform one protective function. A typical IED today can perform 5 to 12 protection functions and 5 to 8 control functions, including controls for separate devices, an auto-reclose function, self-monitoring function, and communication functions etc. It can do this without compromising security of protection – the primary function of IEDs.

The study team estimated the cost of incorporating IEDs to monitor and control critical functions at substations at an average cost of \$110,000/substation, and assumed approximately 80% of the substations would be brought up to Smart Grid levels by 2030 and 100% of new substations would incorporate them.

Table 5-12
Cost of Intelligent Electronic Devices

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Intelligent Electronics & Sensors	58,027	Number of existing substations	80	110,000	110,000	5,106-5,106
Intelligent Electronics Devices (IED)– Relays & Sensors	8,423	Number of new substations	100	110,000	110,000	927-927

Phasor Measurement Technology

Phasor measurement units (PMUs) or synchrophasors provide real-time information about the power system's dynamic performance. Specifically, they take measurements of electrical waves (voltage and current) at strategic points in the transmission system 30 times/second. These measurements are time stamped with signals from global positioning system satellites, which enable PMU data from different utilities to be time-synchronized and combined to create a comprehensive view of the broader electrical system. Widespread installation of PMUs will enhance the nation's ability to monitor and manage the reliability and security of the grid over large areas.

Synchrophasor technology has demonstrated the potential to enhance grid planning and operations processes. Recent industry R&D efforts have focused on developing a variety of applications including situational awareness, small signal stability behavior, event analysis, model validation, state-estimation enhancement, and on-line voltage stability assessment. Currently, about 150 PMUs have been installed in North America (as shown in Figure 5-12), and over 850 additional PMUs will be installed during the next 3 to 5 years across the U.S., as part of the DOE Smart Grid Investment Grant. While the industry continues to explore the use of PMU data in real time and off-line environments, the lack of killer applications has impeded the widespread use of synchrophasor technology. A concerted industry R&D effort is warranted among the research community, end users (grid operators and planners) and EMS vendors to produce production-grade PMU data applications for the users. To that end, EPRI is collaborating with the industry by forming an executive team to help accelerate the deployment of advanced control room applications.

PMUs provide system operators with feedback about the state of the power system with much higher accuracy than the conventional SCADA systems which typically take observations every four seconds. Because PMUs provide more

precise data at a much faster rate, they provide a much more accurate assessment of operating conditions and limits in real time.

The ultimate link between PMUs and other Smart Grid technologies is only now beginning to be revealed. PMUs are themselves an enabling technology that may make investments in advanced communication infrastructures and IEDs more desirable. The full potential benefits of PMUs will not materialize by simply installing PMUs. Wide area measurement systems (WAMS) or wide area control systems (WQACS), which include PMUs, communications infrastructure, other control devices and software application algorithms, will be required to fully realize the potential for PMUs. These other costs are included under separate headings.

The study team expects utilities to install approximately 1,250 PMUs throughout the grid over the next 20 years at a total cost of \$26-39 million.

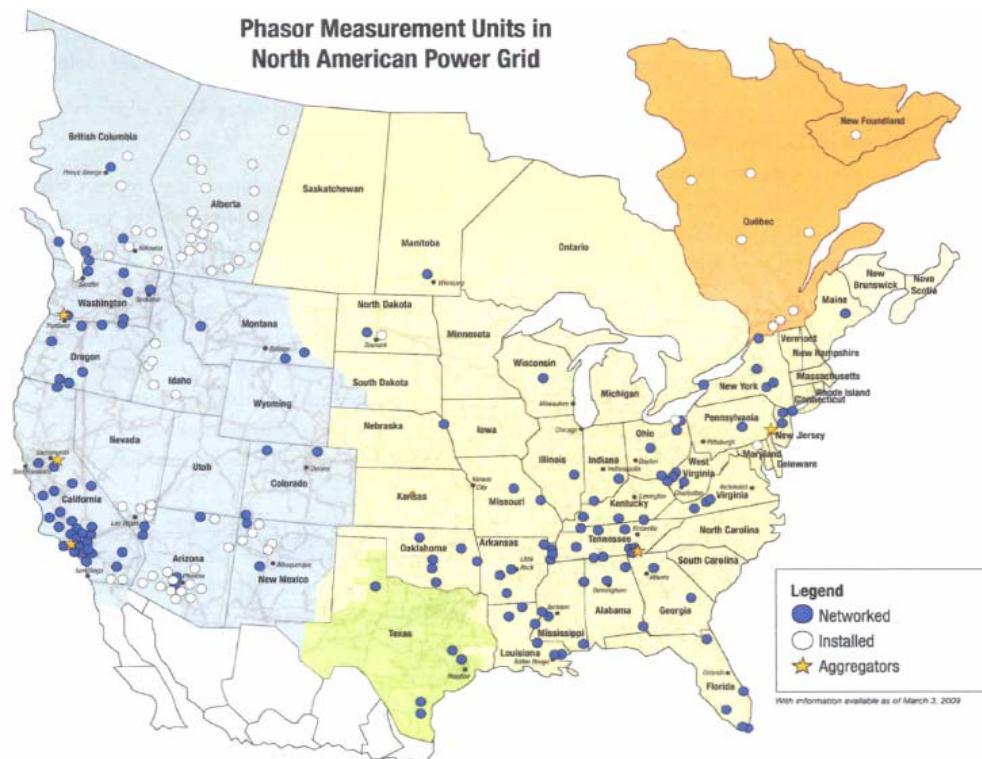


Figure 5-12
Phasor Measurement Units (PMUs) Installed in North America as of September 2009

Table 5-13
Cost of Phasor Measurement Units

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Phasor Measurement Units (PMU)	1,250	Numbers of	100	125,000	125,000	156-156

Cyber Security

Electric utilities have been incorporating cyber security features into their operations since the early 2000s. In recent years as the Smart Grid became increasingly popular, cyber security concerns have increased significantly. While there have to date been few reliable reports of cyber attacks on power systems, there is a great deal of urban lore which suggests alleged attempts to disrupt the reliability of U.S. electricity supply.

Cyber security is an essential element of the Smart Grid. It is the protection needed to ensure the confidentiality and integrity of the digital overlay which is part of the Smart Grid.

The North American Electric Reliability Corporation (NERC) has created eight Critical Infrastructure (CIP) Standards. These include standards for Critical Cyber Asset Identification (CIP002) and Security Management Controls (CIP003) as well as others. Meeting these standards are part of Smart Grid costs.

At present, utilities are considering cyber security as part of information technology (IT) projects for:

- Advanced metering infrastructure
- Plug-in electric vehicle (PEV) management systems
- Distribution automation
- Substation automation
- Transmission upgrades

Interviews with industry suppliers by the EPRI team indicate that as a percentage of IT project costs, cyber security costs range from 10 to 15% of SCADA and distribution automation and approximately 20% for AMI.

Cyber security costs vary by the size of the utility. Urban utilities are likely to be more aggressive in Smart Grid deployment than suburban or rural utilities. For purposes of estimating cyber security costs, three utility sizes were used – small, medium, and large – corresponding to rural, suburban, and urban.

Mere compliance with cyber security standards will not assure security. It is assumed large utilities will use applicable industry standards and best practices, including emerging security standards like NIST's Smart Grid Interoperability Standards Framework and AMI-SEC System Security Requirements, for end-to-end security of the Smart Grid. Most will implement intrusion detection and prevention services (IDS/IPS) as well as security information event management (SIEM). They will likely use a system-of-systems approach to cyber security by deploying International Organization for Standardization and International Electrotechnical Commission (ISO/IEC), National Security Agency InfoSec Assessment Methodology (NSA IAM), Information Systems Audit and Control Association (ISACA), and International Information Systems Security Certification Consortium (ISC2).

Many utility AMI systems will likely use a certificate-based solution for identifying and authenticating trusted devices, authorizing commands and encrypting communications between user entities (people, programs, devices). This solution applies industry standard cryptography to privatize all data transmissions and ensures that communications between authorized entities are confidential, trusted and legitimate.

There is very little information available as to what actual cyber security costs are. To make estimates, the project team interviewed IT suppliers who specialize in cyber security. As a result, these estimates were developed:

Table 5-14
Estimates of Cyber Costs by Utility Size

	Initial Cyber Costs \$K/Utility*	Ongoing Cyber Costs \$K/Year
Small	100	10
Medium	400	40
Large	2,200	200
*To be renewed every 10 years		

To categorize utilities into small, medium and large, the team first identified investor-owned utilities (IOU), rural electric cooperatives (Co-ops), municipal utilities (Munis), and Power agencies. To estimate the number of utilities which would need to make provisions to engage in investments to secure their Smart Grid-related cyber information technology activities, the project team used Platt's 2010 Directory of Electric Power Producers and Distributors (Platts, 2009).

Platts estimates that there are a total of 342 investor-owned utilities (IOUs). This includes 60 holding companies, 29 transmission companies, and a number of other service and wholesale generation companies. Platts estimated 893 rural electric cooperatives (Co-ops), including both distribution and generation and transmission (G&T) entities. Platts' data for municipal utilities (munis) is divided into two categories: One is municipal and local government utilities; the second is the array of federal, state and district government utilities in the U.S.

Table 5-15 summarizes the Platts' estimates. The team subsequently estimated the breakdown of size between each of these utility types.

Table 5-15
Breakdown of Utility Types

Type	Total #	Small		Medium		Large	
		%	#	%	#	%	#
IOU	342	0	-	25	86	75	256
Co-op	893	50	446	40	357	10	90
Muni	2,118	50	1,059	45	953	5	106
Total	3,353		1,505		1,396		452

Table 5-16
Cyber Cost Estimates

Size	Number	Cyber Investment \$M 2010-2030		Ongoing Cyber Cost \$M 2010-2030	
		Per Utility Each 10 Years	Total	Per Utility Per Year	Total
Small	1,505	.10	301.5	.01	30.1
Medium	1,396	.40	1,116.8	.14	111.7
Large	452	2.20	1,988.8	.20	108.8
Total	3,353		3407.1		322.6

Enterprise Back-Office Systems

All large utilities already have enterprise back-office systems which include geographic information systems (GIS), outage management, and distribution management systems (DMS). To enable the Smart Grid, additional features will be required, including an historic data function in conjunction with analytic tools to take in data streams, compare and contrast with historical patterns and look for anomalies in the data.

Enterprise systems will be needed to be upgraded by virtually all utilities. Medium and large utilities will need complete systems of their own. Small utilities may aggregate their needs or use service providers. Table 5-17 summarizes the project teams estimates for enterprise back-office systems.

Table 5-17
Cost of Enterprise Back Office Systems

Utility Size	Number	Back-Office Investment \$M 2010-2030 Each 10 Years	
		Per Utility	Total
Small	1,505	1,000	3,010
Medium	1,396	4,000	11,168
Large	452	20,000	18,080
Total	3,353		32,258

Incremental Ongoing System Maintenance

The project team estimated that the PMUs and sensors installed on transmission lines and substations would cause additional incremental maintenance of \$50,000 per substation.

Table 5-18
Smart Grid Incremental Maintenance

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Incremental Ongoing Maintenance	58,027	Number of existing substations	50	50,000 /yr	50,000 /yr	15,232-15,232
Incremental Ongoing Maintenance	8,423	Number of new substations to meet load growth	100	50,000 /yr	50,000 /yr	4,422-4,422
Incremental Ongoing Maintenance	700	Number of new sub-stations to accommodate renewables	100	50,000 /yr	50,000 /yr	368-368

Impacts on System Operators

Independent system operators (ISOs), transmission system operators (TSOs), and other independent operators (referred to as ISOs here) are making investments in an increasingly robust communications infrastructure as well as an enhanced analytical and forecasting capability. These investments are being made

in response to requirements for ISOs to incorporate increasing functionality in order to maintain reliability, meet load growth, and to comply to new regulations which are increasing grid compliance with FERC rules, increasing the use of distributed resources, demand response and energy efficiency. At the same time, market operations are becoming increasingly more complex, the threat of cyber security is increasing, and pressures is mounting to maintain costs and improve the use of assets.

All ISOs initiated these investments as part of sustaining core capabilities even before the nation began to evolve the concept of a “Smart Grid.” For example, the development of techniques for real-time simulation and enhanced visualization have been under development since the 1990s. Today, they are considered part of the Smart Grid, but would have simply been viewed as necessary improvements a decade ago.

The project team identified three ISO functions which are considered part of the Smart Grid in this study. They include:

1. Enhancing the visibility of the grid (transparency), increasing reliability, and energy efficiency.
2. Enable the effective integration of increasing amounts of distributed resources including renewables, energy storage, and demand response.
3. Enable effective response to increasingly sophisticated cyber and physical security threats including natural events.

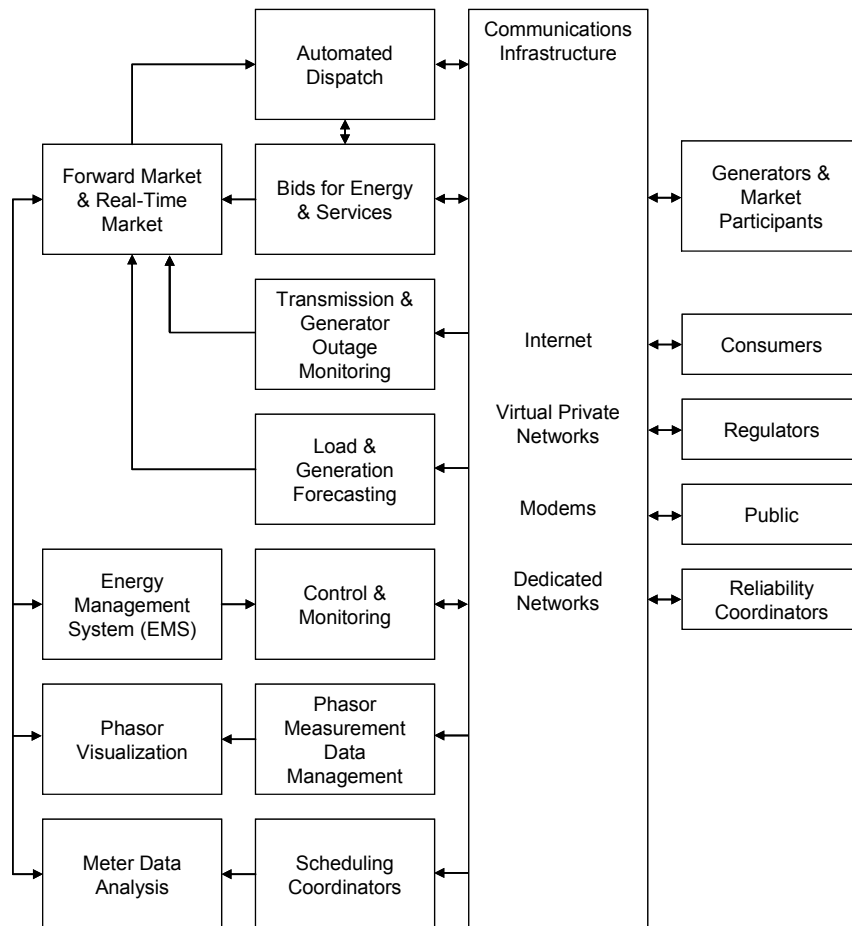


Figure 5-13
Key Components of an ISO Infrastructure

Figure 5-13 illustrates the key applications that form an ISO. The functional enhancements which the Smart Grid is expected to yield will require changes in these applications in the following areas:

- Communications – The increasing number of external interfaces will necessitate that telemetry data is compatible with IEC 61850. This will require retrofits and upgrades. In addition, the Smart Grid will contain many more transmission line sensors and sensors from wind and solar installations.
- Prices-To-Devices – Truly enabling consumers to respond to variations in prices and system constraints will require the ability to broadcast that information to consumers both through the Internet and through secure, automated area networks.
- Upgrade to NIST-Proposed Standards – The National Institute for Standards and Technology (NIST) has established a Smart Grid Interoperability Panel (SGIP), and the panel is developing Priority Action Plans (PAP) to encourage adoption of standard business practices and interface specifications. It is likely that these interfaces will require widespread adoption of the Common Information Model (CIM).

- Forecasting – Developing far more accurate data to forecast renewable energy production (particularly wind and solar) including very short-term forecasts and ramp rates. In addition, it will be necessary to forecast demand response participation.
- Cyber Security – The North American Electric Reliability Corporation is developing Critical Infrastructure Protection Standards (CIP) to meet Federal Energy Regulatory Commission (FERC) and Congressional requests.
- Integrate Synchrophasors – Integrating synchrophasor data sources with visualization and to enable advanced-state estimation and dynamic stability analysis incorporating the data from numerous new distributed generation sources.
- Evolve New Markets – The advent of widespread consumer connectivity coupled with increasing participation of third parties allows for new markets to evolve. The ISO's system will need to be sufficiently flexible so as to allow the evolution of new markets.
- Other Applications – Individual ISOs may add other functionality like the ability to quickly add new market participants, to improve outage management data and other enhancements.

Each of these and other features will require an ongoing investment in the ISO's applications.

The costs of the enhancements to an ISO's system to respond to changes in the applications are very difficult to estimate. Each ISO is in a different phase of development. Each varies as to the projected nature and penetration of distributed resources and as to the extent of other market participants.

The project team interviewed executives from several ISOs including PJM, CAISO, NEISO, and NYISO in order to establish estimates for the costs which an ISO will occur in order to accommodate the functionality required to achieve Smart Grid goals. Their informal estimates varied but generally included five or six full-time staff (\$2.4 million per year) and at least several million dollars annually in software. For one ISO, this totaled 10% of its annual budget or \$12 million per year.

The following are the ten regional power markets in the U.S.

- California (CAISO)
- Midwest (MISO)
- New England (ISO-NE)
- New York (NYISO)
- Northwest
- PJM
- Southeast
- Southwest

- SPP
- Texas (ERCOT)

Table 5-19 summarizes the estimated cost of alignment of ISOs with Smart Grid requirements.

Table 5-19
Cost to Align ISOs with Smart Grids

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
ISO Smart Grid	10	Regional markets	100	12/yr	12/yr	2,400-2,400

Summary of Transmission and Substations Costs

The cumulative cost for bringing the nation's transmission and substations system up to the performance levels required for Smart Grid operation is estimated to cost between \$6,312 and \$7,280 million by 2030, as shown in the summary Table 5-20, below. Smart Grid related investment in the transmission system will continue well beyond 2030. This does not include related investments to meet load growth which are estimated to cost between \$56,350 and \$63,702 million by 2030.

Table 5-20
Smart Grid Transmission and Substation Costs

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Dynamic-Thermal Circuit Rating	11,340	Number of substations with one DTCR unit/7.5 miles of line	100	10,000	20,000	113.4-226.8
Substation & Transmission Line Sensors	58,027	Number of existing substations	50	50,000	100,000	1,451-2,901
Transmission Short-Circuit Current Limiters	58,017	Number of substations	2	500,000	500,000	580.3-580.3
Storage for Bulk Transmission Wholesale Services w/o Regulation	5,800,000	kW	100	810	1045	4,698-6,061
Storage for Bulk Transmission Wholesale Services with Regulation	2,800,000	kW	100	810	1045	2,268-2,926
FACTS Devices	330	Numbers of	100	Various	Various	4,175-4,925
Communications: Core Infrastructure for Smart Substations	58,027	Number of substations	80	50,000	75,000	2,321-3,481
Communications to Substations	58,027	Number of substations	80	\$1,200/mo	\$1,200/mo	668.5-668.5
Phasor Measurement Units (PMU)	1,250	Numbers of	100	125,000	125,000	156-156

Table 5-20 (continued)
Smart Grid Transmission and Substation Costs

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Intelligent Electronics Devices (IED) – Relays & Sensors	58,027	Number of substations	80	110,000	150,000	5,106-6,963
Cyber Security – Enterprise-Wide	1,454	Number of utilities	100	100,000*	2,200,000*	3,729.2-3,729.2**
Enterprise Back Office System – GIS, Outage management, Distribution Management	1,454	Number of utilities	100	1,000,000*	20,000,000*	32,258-32,258
ISO Smart Grid	10	Regional markets	100	12,000,000/yr	12,000,000/yr	2,400-2,400
Incremental Ongoing System Maintenance***	58,027	Numbers of substations	50	50,000/yr	50,000/yr	15,232-15,232
Total						75,157-82,509
SCCL will begin in 2020 and reach a 2% penetration rising to 7% by 2030. *Varies by size. **Includes annual cost. ***Additional ongoing maintenance costs are included in individual cost components.						

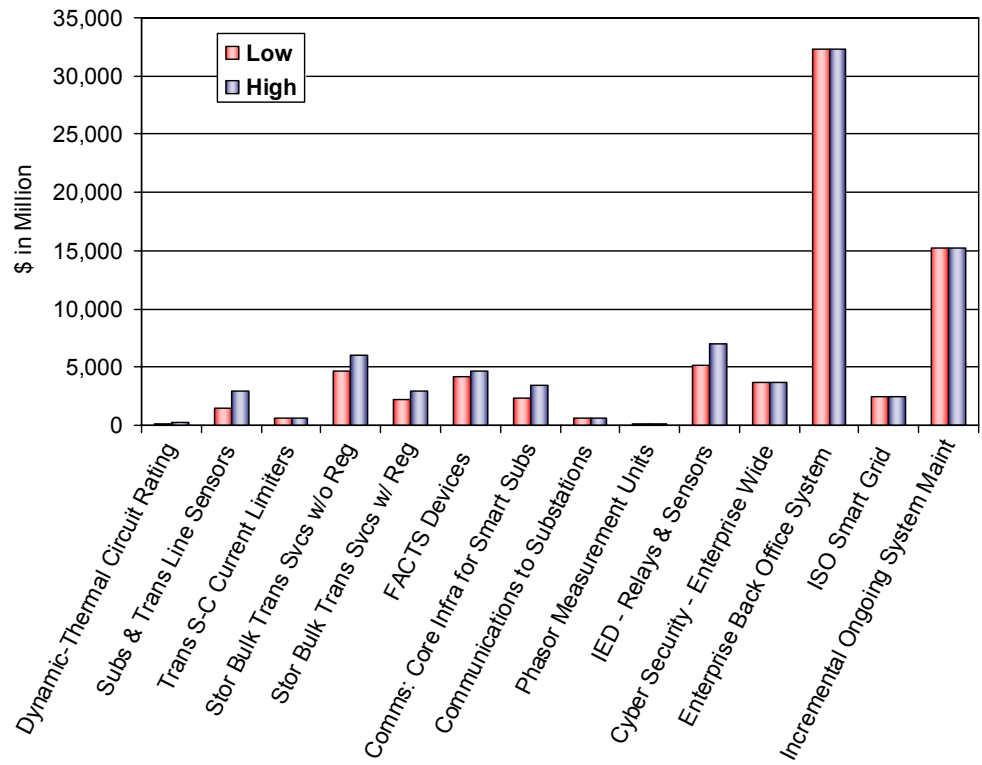


Figure 5-14
Smart Grid Transmission and Substation Costs

Table 5-21
Smart Grid Transmission and Substation Cost to Meet Load Growth

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low- High \$M
Substation & Transmission Line Sensors	8,423	Number of new substations	100	50,000	100,000	421-631.7
Communications: Core Infrastructure for Smart Substations	8,423	Number of substations	100	50,000	75,000	421-632
Transmission Systems & Communications to Substations	8,423	Number of substations	100	14,400	14,400	121-121
Intelligent Electronics Devices (IED) – Relays & Sensors	58,027	Number of substations	80	110,000	150,000	927-1,264
Incremental Ongoing System Maintenance	8,423	Number of substations	100	50,000	50,000	4,422-4422
Total						6,312-7,280

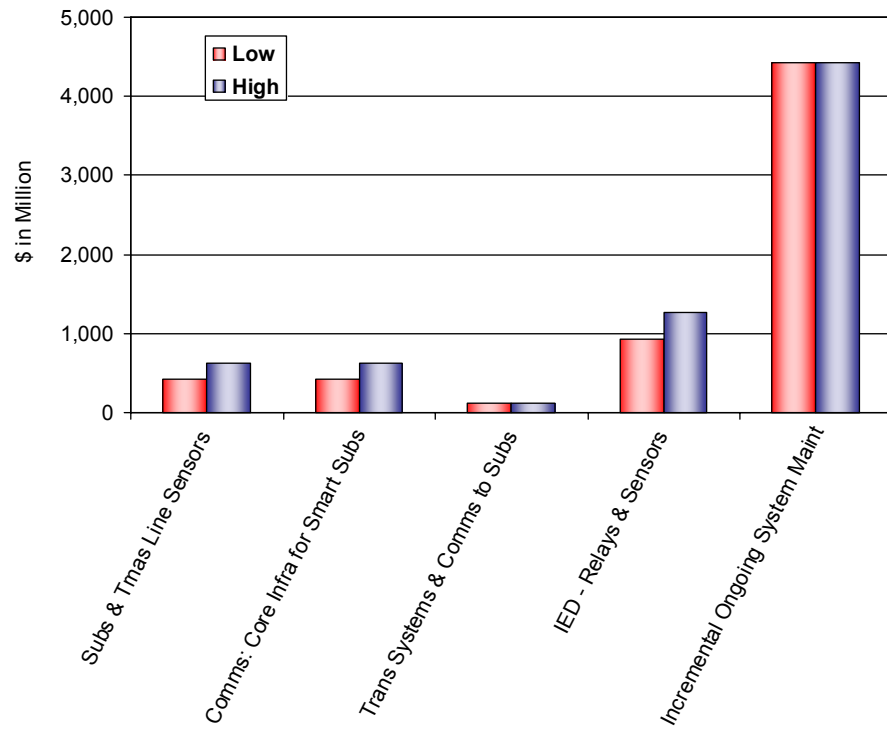


Figure 5-15
Smart Grid Transmission and Substation Cost to Meet Load Growth

Table 5-22
Smart Grid Transmission and Substation Costs to Meet Renewables

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low– High \$M
Communications: Core Infrastructure for Smart Substations	700	Number of substations	100	50,000	75,000	35-53
Transmission Systems & Communications to Substations	700	Number of substations	100	14,400	14,400	10-10
Phasor Measurement Units (PMU)	700	Number of substations	100	125,000	125,000	88-88
Intelligent Electronics Devices (IED) – Relays & Sensors	700	Number of substations	100	110,000	150,000	77-105
Incremental Ongoing System Maintenance	700	Number of substations	100	50,000/yr	50,000/yr	368- 368
Total						577- 623

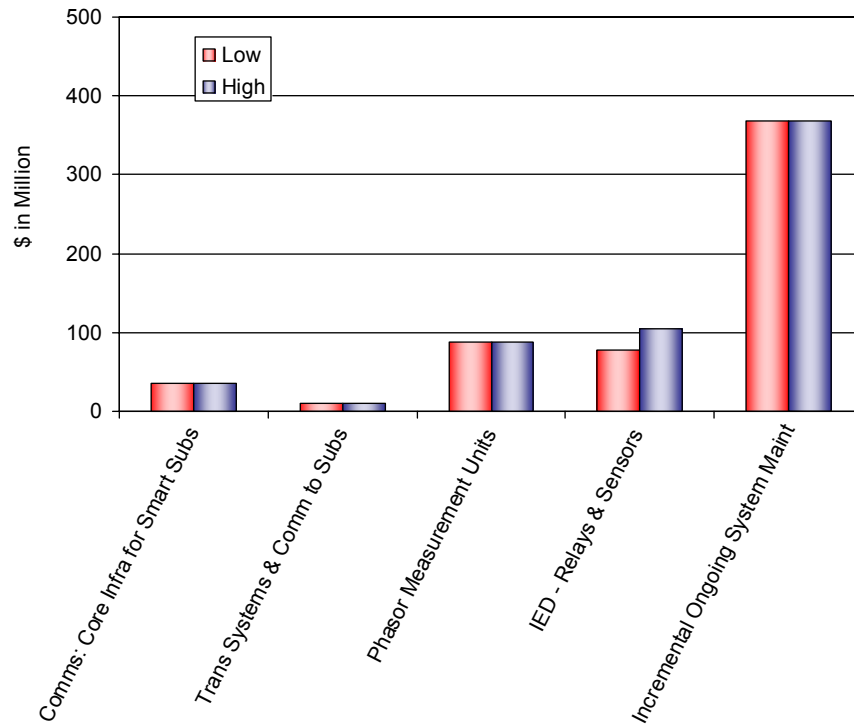


Figure 5-16
Smart Grid Transmission and Substation Costs to Meet Renewables

Table 5-23
Total Smart Grid Transmission and Substation Costs

Costs to Upgrade the Existing System (\$M)		
	Low	High
Transmission and substations	75,157	82,509
Costs to Embed Smart Grid Functionality While Accommodating Load Growth (\$M)		
	Low	High
Transmission and substations	6,312	7,281
Costs to Embed Smart Grid Functionality While Accommodating Large-Scale Renewables (\$M)		
	Low	High
Transmission and substations	577	623
Total	82,046	90,413

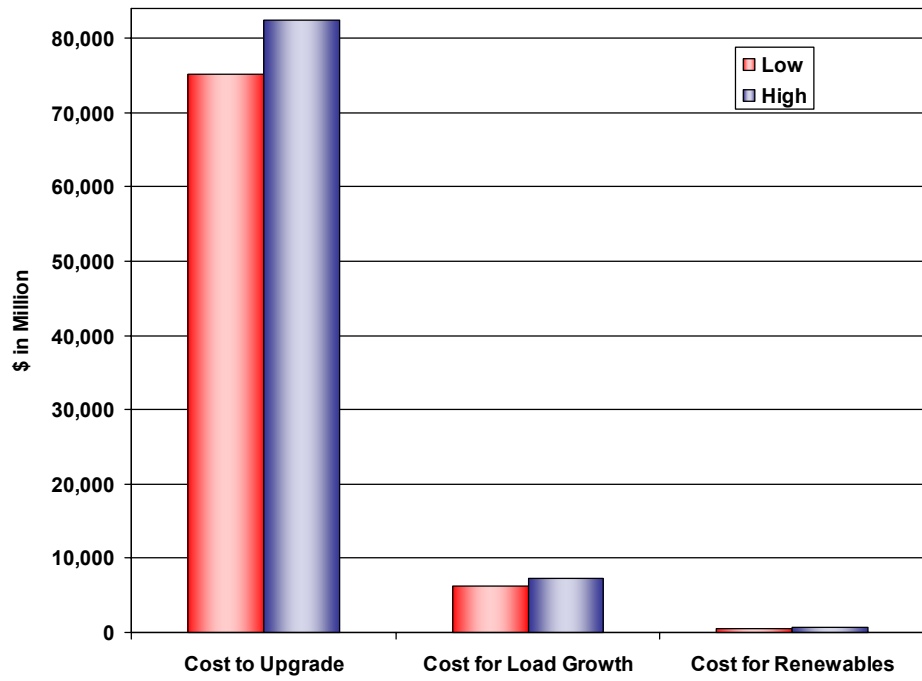


Figure 5-17
Total Smart Grid Transmission and Substation Costs



Section 6: Distribution

While a small percentage of electricity customers are served directly from the transmission system, the vast majority of the 165 million customers in the U.S. are served by the distribution system, which is comprised of a complex network of substations, lines, poles, metering, billing and related systems to support the retail side of electricity delivery.

The study team estimated the cost of Smart Grid distribution investment between \$309 to \$403 billion over the next 20 years.

Introduction

Utility distribution systems are generally challenged by an aging infrastructure, conventional designs, and increased demands for digital-quality power. There are a few exceptions where distribution utilities have implemented a reasonably smart grid and are working to make it smarter – but these are the exception. Compared to the transmission system, the greater complexity, exposure, and geographic reach of the distribution system results in inherently lower reliability, reduced power quality, and greater vulnerability to disruptions of any kind. Using a reliability measure of average total duration of the interruptions experienced by a customer in a year, over 90% of the minutes lost by consumers are attributable to distribution events. In 2004, EPRI estimated that a fully automated distribution system could improve reliability levels by 40%. Advances in Smart Grid technologies are not a substitute for good maintenance practices, inspection, and vegetation management.

Investment in the distribution system has averaged \$12 to \$14 billion per year for last few decades, primarily to meet load growth, which includes both new connects and upgrades for existing customers. An urban utility may have less than 50 feet of distribution circuit per customer, while a rural utility can have more than 300 feet of primary distribution circuit per customer. Assuming a rough average 100 feet of line for each of the 165 million U.S. customers indicates the U.S. has an installed base of more than 3 million miles of distribution line. Upgrading a system this extensive to the level of performance required in a Smart Grid will require a substantial investment.

Estimates of the cost of individual distribution system components in this analysis were based largely upon utility experience in deploying the first wave of Smart Grid investment. Estimates of AMI and distribution automation

investment were drawn, for example, from FirstEnergy, SCE, SDG&E, Dayton Power & Light, FortisAlberta, Inc, and Idaho Power, among others. Representative costs are shown in the two tables below (FirstEnergy, 2009).

Table 6-1

Distribution Cost Estimates Per Feeder (FirstEnergy, 2009)

Function	No. of Feeders	Total Cost	Cost/Feeder
Distribution Automation	59	\$18.2 M	\$308,000
Volt/VAR Control	33	\$8.5 M	\$258,000

Table 6-2

Distribution Cost Estimates Per Customer (FirstEnergy, 2009)

Function	No. of Customers	Total Cost	Cost/Customer
Direct Load Control	34,000	\$24.6 M	\$728
AMI with DR	44,000	\$41.2 M	\$940

Cost Components for the Smart Grid: Distribution

Smart Grid investments in the distribution system entail wider high bandwidth communications to all substations, intelligent electronic devices (IED) that provide adaptable control and protection systems, complete distribution system monitoring that is integrated with larger asset management systems, collaborative distributed intelligence, including dynamic sharing of computational resources of all intelligent electronic devices and distributed command and control to mitigate power quality events and improve reliability and system performance. The key cost components for the distribution portion of the Smart Grid are as follows:

- Communications between all digital devices on the distribution system including to feeders for AMI and distributed smart circuits
- Distribution automation
- Distribution feeder circuit automation
 - Intelligent reclosers and relays at the head end and along feeders
 - Power electronics, including distribution short circuit current limiters
 - Voltage and VAR control on feeders
- Intelligent universal transformers
- Advanced metering infrastructure (AMI)
- Local controllers in buildings, on microgrids, or on distribution systems for local area networks

Communications

Communications constitute the critical backbone for integrating customer demand with utility operations. Detailed, real-time information is key to

effectively managing a system as large and dynamic as the distribution power grid. Each smart meter in the advanced metering infrastructure (AMI), described later in this section, must be able to communicate with a wide range of user control systems, as well as reliably and securely communicating performance data, price signals, and customer information to and from an electric utility's back-haul system.

No single technology is optimal for all applications. Among the communications media now being used for AMI applications are cellular networks, licensed and unlicensed radio, and power line communications. In addition to the media, the type of network is also an important part of communications design. Networks used for Smart Grid applications include fixed wireless, mesh networks, and a combination of the two. Several other network configurations, including Wi-Fi and Internet networks are also under investigation.

Interoperability remains one of the most critical success factors for Smart Grid communications. There is growing interest in the potential use of the Internet Protocol Suite (TCP/IP) as a networking protocol that could run over many different communication technologies. In June, 2009, EPRI submitted a *Report to NIST on the Smart Grid Interoperability Standards Roadmap* that became the starting point for NIST's own roadmap, released in September, 2009 (www.nist.gov/smartgrid).

Communication architectures remain diverse for integrating residential devices with the grid. Some utilities envision using the meter as a gateway to the home for price and feedback information, whereas others envision using the Internet or other communication channels. Radio frequency (RF) networks communicating in both licensed and unlicensed radio bands and have been chosen by the majority of Smart Grid deployments in the U.S. Mesh networks incorporate multi-hop technology where each node in the network can communicate with any other node. Star networks utilize a central tower that can communicate with a large number of end devices over a wide area. Each type has certain advantages and disadvantages, and is selected based on the unique needs and circumstances of the utility. Power line carrier networks where communications are carried via electric power lines are also used by a large number of utilities both in the U.S. and abroad.

Communications to feeders for AMI and distribution smart circuits were estimated to cost about \$20,000 per feeder, and to be fully installed on 80% of existing feeders and 100% of new feeders by 2030, for a total cost of nearly \$9 billion.

Table 6-3

Cost of Communication to Feeders for AMI

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost \$M
Communication to Existing Feeders for AMI & Distribution Smart Circuits	464,216	Number of feeders	80	20,000	20,000	7,427
Communication to New Feeders for AMI & Distribution Smart Circuits	67,384	Number of feeders	100	20,000	20,000	1,348

Distribution Automation

Distribution automation (DA) involves the integration of SCADA systems, advanced distribution sensors, advanced IED's and advanced two-way communication systems to optimize system performance. In a dense urban network it will also include network transformers and network protectors. The SCADA system collects and reports voltage levels, current demand, MVA, VAR flow, equipment state, operational state, and event logging, among others, allowing operators to remotely control capacitor banks, breakers and voltage regulation. Substation automation, when combined with automated switches, reclosers, and capacitors, will enable full Smart Grid functionality.

This includes not only building intelligence into the distribution substations and into the metering infrastructure but also into the distribution feeder circuits and components that link these two essential parts of the grid. This means automating switches on the distribution system to allow automatic reconfiguration, automating protection systems and adapting them to facilitate reconfiguration and integration of DER, integrating power-electronic based controllers and other technologies to improve reliability and system performance, and optimizing system performance through voltage and VAR control to reduce losses, improve power quality and facilitate the integration of renewable resources.

- **Intelligent head-end feeder reclosers and relays.** Replacing electromechanical protection systems with microprocessor-based, intelligent relays and reclosers are an integral part of Smart Grid operation. Advantages include multiple functionality, including both instantaneous and time-overcurrent protection, greater sensitivity, better coordination with other devices, and the ability for self diagnosis. Approximately 70% of all feeders will include intelligent reclosers and relays by 2030, at an estimated unit cost of \$50,000.

- **Intelligent reclosers.** The use of intelligent switching and protection devices on feeders (referred to as “mid-point or tie-reclosers”) to allow isolation of segments of feeders to enhance reliability. Approximately 25% of all feeders will have intelligent reclosers and relays by 2030 at an estimated cost of \$100,000 to \$150,000.
- **Remotely controlled switches.** Remotely controlled switches contain distributed intelligence and use peer-to-peer communications to take actions without the need for central control intervention in order to isolate faults and restore power quickly in the event of an outage. As a result, distribution system operators will no longer be the only ones that can perform that function. It is estimated that 5% of all feeders will use one remotely controlled switch at a cost of \$50,000 to \$75,000 by 2030.
- **Power electronics, including distribution short circuit current limiters.** Advances in power electronics allow not only greater fault protection but flexible conversion between different frequencies, phasing, and voltages while still producing a proper ac voltage to the end user. Power electronics will be deployed on about 5% of 57,000 substations by 2030 at an average cost \$80,000/package.
- **Voltage and VAR control on feeders.** Voltage/VAR controls are a basic requirement for all electric distribution feeders to maintain acceptable voltage at all points along the feeder and to maintain a high power factor. Recent efforts by distribution utilities to improve efficiency, reduce demand, and achieve better asset utilization, have indicated the importance of voltage/VAR control and optimization. Utilities continue to face system losses from reactive load, such as washing machines, air conditioners. By optimizing voltage/VAR control great efficiencies can be realized. An estimated 55% of the 566,000 distribution feeders will include voltage/VAR control by 2030, at an average cost of \$258,000/feeder.

Smart Grid software will be able to combine information flowing from the automated substations with SCADA data points throughout the distribution system to analyze and recommend re-configuration of the distribution system for optimum performance. Circuit optimization will minimize line losses and integrate customer data from AMI to regulate voltage while still maintaining acceptable levels for customers. This functionality will help support conservation voltage reduction (CVR) strategies to achieve energy savings. As the Smart Grid evolves, this one dimension of optimization will expand to include optimization of reliability, power quality and asset management – among others.

By 2030, an estimated 55% of all existing distribution feeders will be integrated with advanced distribution automation systems at a cost of \$308,000 per feeder, and 100% of all new feeders will be equipped by 2030. In this analysis, there are additional costs assumed for automation of the feeders themselves. The Smart Grid investment of distribution automation is estimated at nearly \$96 billion, as shown in Table 6-4.

Table 6-4
Cost of Distribution Automation

Technology	Total Units	Units	% Sat	Cost/Unit Low \$	Cost/Unit High\$	Total Cost \$mill
Distribution Automation	464,216	Number of existing feeders	55	Varies	Varies	124,134-177,008
Distribution Automation	67,384	Number of new feeders	100	308,000	308,000	20,754-20,754

As shown in Table 6-5, the total investment required for distribution feeder automation exceeds \$92 billion from 2010 to 2030.

Table 6-5

Cost of Distribution Feeder Automation for Existing Systems

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Communications to Feeders for AMI & Distribution Smart Circuits	464,216	Number of feeders	80	20,000	20,000	4,428-4,428
Head End of Feeders – Intelligent Reclosers & Relays	464,216	Number of feeders	70	50,000*	50,000*	16,248-16,248
Power Electronics, Include Distribution Short-Circuit Current Limiters	58,027	Number of substations	5	80,000	80,000	2,321-2,321
Smart Switches, Reclosers, Monitored Capacitor Banks, Regulators & Circuit Improvement	464,216	Number of feeders	55	308,000	308,000	78,638-78,638
Voltage & VAR Control on Feeders	464,216	Number of feeders	55	60,000	258,000	15,319-65,873
Intelligent Reclosers	464,216	Number of feeders	25	100,000	150,000	11,605-17,408
Remotely Controlled Switches	464,216	Number of feeders	5	50,000	75,000	1,161-1,741
Direct Load Control (not integrated with AMI)	123,949,916	Number of customers	5 declining to 0	100	100	1,859-1,859
ElectriNet Controllers	464,216	Number of feeders	10	50,000	100,000	2,321-4,642
Incremental Ongoing System Maintenance**						
Total Distribution Feeder Cost						124,134-177,008
*Incremental cost – i.e., excludes the cost of the “switch” itself.						
**Incremental Ongoing System Maintenance expenses are included in individual cost components.						

Table 6-6

Cost of Distribution Feeder Automation for New Feeders

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Communications to Feeders for AMI & Distribution Smart Circuits	67,384	Number of feeders	100	20,000	20,000	1,348-1,348
Head End of Feeders – Intelligent Reclosers & Relays	67,384	Number of feeders	100	50,000*	50,000*	3,369-3,369
Power Electronics, Include Distribution Short-Circuit Current Limiters	8,423	Number of substations	100	80,000	80,000	6,738-6,738
Smart Switches, Reclosers, Monitored Capacitor Banks, Regulators & Circuit Improvement	67,384	Number of feeders		308,000	308,000	20,754-20,754
Voltage & VAR Control on Feeders	67,384	Number of feeders	100	258,000	258,000	4,043-17,385
Intelligent Reclosers	67,384	Number of feeders	25	100,000	150,000	1,685-2,527
Remotely Controlled Switches	67,384	Number of feeders	5	50,000	75,000	169-253
ElectriNet Controllers	67,384	Number of feeders	25	50,000	100,000	842-1,684
Incremental Ongoing System Maintenance**						
Total Distribution Feeder Cost						38,948-54,059
*Incremental cost – i.e., excludes the cost of the “switch” itself.						
**Incremental Ongoing System Maintenance expenses are included in individual cost components.						

Intelligent Universal Transformers

Conventional transformers suffer from poor energy conversion efficiency at partial loads, use liquid dielectrics that can result in costly spill cleanups, and provide only one function—stepping voltage. These transformers do not provide real-time voltage regulation nor monitoring capabilities, and do not incorporate a communication link. At the same time, they require costly spare inventories for multiple unit ratings, do not allow supply of three-phase power from a single-phase circuit, and are not parts-wise repairable. Future distribution transformers will also need to be an interface point for distributed resources, from storage to plug-in hybrid electric vehicles.

The intelligent universal transformer (IUT) is a first-generation, power-electronic replacement of conventional distribution transformers. EPRI has developed an IUT which can serve as a “Renewable Energy Grid Interface” (REGI). The new concept includes a bi-directional power interface that provides direct integration of photovoltaic systems, storage systems, and electric vehicle charging. It will also incorporate command and control functions for system integration, local management, and islanding.

REGI will become a key enabler in the overall Smart Grid development strategy. It plays a transformational role by combining the traditional functions of a power transformer with new interface capabilities. It can seamlessly integrate widespread renewable energy technologies, including energy storage, electric vehicles, and demand response, while also providing an architecture that allows the operation of reliable local energy networks. The controller will interface with distribution management systems, energy management systems, and demand response systems to optimize overall grid performance and improve reliability.

The cost of the IUT, as shown in Table 6-7, are expected to decline dramatically over the next 20 years, from \$1.50 to 2.00/W today to \$0.20/W in 2030. As a result, deployment is expected to grow rapidly, from for example, 10,000 25-kW units in 2015 to 1 million in 2030.

Table 6-7
Declining Costs and Growing Deployment of the IUT

IUT	2010	2015	2020	2025	2030
\$/Watt With Storage Integration Option	\$1.50-\$2.00	\$.75	\$.50	\$.35	\$.20
25 kW No. Units	Demo	10 x 10 ³	50 x 10 ³	200 x 10 ³	1 x 10 ⁶
50 kW No. Units	Demo	5 x 10 ³	25 x 10 ³	100 x 10 ³	500 x 10 ³
\$/watt With PV Inverter	\$3.00-\$1.00	\$.75	\$.50	\$.35	\$.20
25 kW No. Units	Demo	10 x 10 ³	50 x 10 ³	200 x 10 ³	1 x 10 ⁶
50 kW No. Units	Demo	5 x 10 ³	25 x 10 ³	100 x 10 ³	500 x 10 ³

Total Smart Grid investment in IUTs through 2030, based upon the expected deployment of three million units, ranging in cost from \$7,500 to \$100,000, is \$76 to \$131 billion, as shown in Table 6-8.

Table 6-8
Cost of Intelligent Universal Transformers *

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Intelligent Universal Transformer With Storage	1,500,000	Number of	various	37,500	100,000	12,563-12,688
Intelligent Universal Transformer With PV Inverter	1,500,000	Number of	various	7,500	50,000	12,437-12,937
Total IUT Cost	3,000,000	Number of	various			25,000-25,625

Note: It is assumed that 50% of IUTs will be installed on existing feeders and 50% will be installed on new feeders added for load growth.

* IUT may include some part of energy storage costs. Energy storage cost would be \$500/ kWh of storage installed.

Advanced Metering Infrastructure (AMI)

An advanced metering infrastructure (AMI) involves two-way communications with smart meters, customer and operational data bases, and various energy management systems. AMI, along with new rate designs, will provide consumers with the ability to reduce electricity bills by using electricity more efficiently, to participate in Demand Response Programs and to individualize service, and provide utilities with the ability to operate the electricity system more robustly.

Smart meters are the main component of AMI and generally the first technology deployed by an electric utility in a Smart Grid program. Although smart meters have been used by commercial and industrial customers for decades, only recently have they become economical for widespread use in residential settings. The broader AMI system in which smart meters operate involves the two-way communication network to exchange energy usage, price and curtailment signals, and operational control signals. Integral to AMI is a common enterprise bus network architecture linking all key enterprise systems including meter data management, customer care, auto-demand response system, and energy management. The goal is to provide a highly secure, resilient and flexible technology upgrade to the core business of electric utilities and to integrate electricity usage into Smart Grid dynamics. Three basic functions are involved:

- **Smart meters** capable of two-way communication with the utility, remotely programmable firmware, and, optionally, a remotely manageable service disconnect switch. In addition to consumption measurements, smart meter functionality includes: voltage measurement and alarms that can be integrated with distribution automation projects to maximize CVR benefits, and interval data to support dynamic pricing and demand response programs.
- **Communications** system that is highly secure (encrypted), redundant and self-healing, and related hardware and software systems to communicate between smart meters, substation and distribution automation equipment, customer energy management systems, and head-end software applications / meter data management systems.
- **Meter data management system** capable of storing and organizing data, allowing for advanced analysis and processing, and interfacing AMI head-ends with a range of other enterprise software applications.

AMI Cost Assumptions

- **Residential meter** costs are based more on volume than other factors
 - Meter + AMI \$40-80/unit
 - Meter + AMI + Disconnect \$70-130/meter
 - Meter + AMI + Disconnect+ HAN \$80-140/meter
- **Commercial and Industrial meter** costs are based more on features selected than other factors.
 - Meter + communications \$120-150/meter

- GT&D
- Meter \$1500-5000
- Installation costs
 - Residential \$7-10/meter
 - Commercial and industrial \$20-65/meter
 - AMI network and backhaul equipment \$3-11/endpoint
 - Head end software and integration \$4-10/endpoint
 - System initiation and management \$2-4/endpoint
- Ongoing maintenance \$3-11/year/endpoint

AMI Costs for the Smart Grid

Based upon these unit costs and the assumption of an average of 83% saturation, the total costs for the AMI portion of Smart Grid investment from 2010 to 2030 ranges from \$15 to \$42 billion, as shown in Table 6-9.

Table 6-9
Cost of Advanced Metering Infrastructure (AMI) for Existing Customers

Technology	Total Units	Units	% Sat	Cost/Unit Low\$	Cost/Unit High\$	Total Cost Low-High \$M
Advanced Meter Infrastructure (AMI) Residential Meters	123,949,9166	Number of customers	80	70	140	7,437-13,387
Installation of Residential Meters	123,949,9166	Number of customers	80	7	15	694-1,487
Advanced Meter Infrastructure (AMI) Commercial & Industrial Meters	18,170,986	Number of customers	100	120	500	2,240-9,284
Installation of Commercial & Industrial Meters	18,170,886	Number of customers	100	20	65	364-1,184
Other AMI Costs	142,121,652	Number of customers	83	Various	Various	1,062-2,949
Ongoing System Maintenance	142,121,652	Number of customers	83	3/year	11/year	3,716-13,624
Total AMI Costs	164,982,450	Number of customers	83			15,513-41,915

Table 6-10

Cost of Advanced Metering Infrastructure (AMI) for New Customers

Technology	Total Units	Units	% Sat	Cost/Unit Low\$	Cost/Unit High\$	Total Cost Low-High \$M
Advanced Meter Infrastructure (AMI) Residential Meters	19,978,760	Number of customers	80	70	140	1,498-2,697
Installation of Residential Meters	19,978,760	Number of customers	80	7	15	140-300
Advanced Meter Infrastructure (AMI) Commercial & Industrial Meters	2,800,932	Number of customers	100	120	500	360-1,493
Installation of Commercial & Industrial Meters	2,800,932	Number of customers	100	20	65	59-190
Other AMI Costs	22,907,634	Number of customers	100	Various	Various	586-1,523
Ongoing System Maintenance	22,907,634	Number of customers	100	3/year	11/year	722-2,646
Total AMI Costs	22,907,634	Number of customers	100			3,365-8,850

Controllers for Local Energy Network

Local energy networks are means by which consumers can get involved in managing electricity by reducing the time and effort required to change how they use electricity. If usage decisions can be categorized so they are implemented based on current information, and that information can be readily collected and processed, then consumers will purchase and operate such a system, install and operate a home area network (HAN.) A HAN is an electronic information network, connected to a central or “master” control which acts as an energy management system (EMS.) The HAN accommodates the flow of information to and from network nodes. Each node is associated with a device or element of the household’s electric system. Nodes can be hard-wired devices that account for substantial portions of electricity used like the HVAC, a pool pump, lighting circuits, or smaller plug loads like TVs, entertainment centers, and a multitude of chargers. Communication among devices and the EMS is accomplished through wireless, wired, or power line carrier media that define and make operational the HAN.

An EMS is a decision processor which controls energy use within the building, organizes response to Demand Response participation, controls distributed generation, electric vehicle charging and storage and interfaces with retail electricity markets. An EMS is an intelligent device that acts as the coordinator for the devices that comprise the home area network. It maintains certain user-defined rules for interior temperature settings as well as when appliances and other household loads should not ever turn off. These rules can be based on the price of electricity at a particular instance of time (e.g., when it exceeds some threshold), on current conditions (e.g., the time of day a household service is typically expected to run), or in response to a command to do so from an external agent (e.g., a curtailment order from a curtailment service provider).

The EMS is the controller, making decisions based on exigent conditions viewed in light of a predefined instruction set, and the HAN is the neural system that conveys information about the state of the nodes and delivers commands and verifies their receipt and enactment. The EMS is an electronic device whose purpose is to manage household electricity consumption better than the household can do so in its absence. Achieving that result requires the very difficult task of understanding how the household members use and value electricity, establishing ways for them to negotiate differences in value systems, and establishing a holistic household utility function that establishes the relative value under different system states and executes pre-established operational decisions.

Architectures are evolving for marrying the Smart Grid with low-carbon central generation, local energy networks (LEN) and electric transportation. LEN includes a combination of end-use energy service devices, distributed generation, local energy storage, and integrated demand-response functions at the building, neighborhood, campus or community level. These architectures to facilitate a highly interactive network based upon a distributed, hierarchical control structure

that defines the interactions of LEN, distribution systems and the bulk power system (Gellings, 2010).

These architectures facilitate the inclusion of multiple centralized generation sources linked through high-voltage networks. The design implies full flexibility to transport power over long distances to optimize generation resources and to deliver the power to load centers in the most efficient manner possible. In particular, these architectures enable the inclusion of inherently less controllable variable resources such as wind, solar and certain kinetic energy sources by offering a variety of balancing resources. To enable integration of these elements, these architectures must address the key transformative technical challenges shown in Table 6-11.

Table 6-11

Key Technical Challenges for Tomorrow's Distribution Architecture

Operational Area	Modeling, Simulation, and Control	Monitoring, Data Management, and Visualization	Advanced Control Architecture	Control Structure
System Operations	Physical and distributed models, real time simulation, local and global system constraints	Widespread sensor integration with simulation tools and expert systems. visualization tools for decision making	Distributed intelligence and control architecture – local optimization integrated with system management integration with simulation tools and expert systems. visualization tools for decision making	Autonomous Control Devices
Market Operations	Aggregate resource models, local vs. global optimization	Market and participant awareness	Market structures to support distributed control architecture	Autonomous Control Devices

The concept of these distribution architectures is to optimize performance locally without complete dependence on the bulk power system infrastructure by taking advantage of the overall infrastructure to optimize energy efficiency and energy use. A key transformative element will be the development of distributed, intelligent control devices that will be able to constantly balance generation and load and more at the device, home, neighborhood, city, area and regional levels. To achieve this vision, specific controllers will need to be designed and prototyped, tested and demonstrated in field applications to verify their interactions.

One of the key advantages of the new architecture is the efficiency that can be achieved in terms of energy savings and tons of avoided emissions. Estimated energy savings by 2030 are between 56 to 203 billion kWh, with a corresponding

reduction in annual carbon emissions of 60 to 211 million metric tons of CO₂. On this basis, the environmental value to the U.S. is equivalent to converting 14 to 50 million cars into zero-emission vehicles each year (EPRI 1016905).

As shown in Table 6-12, the estimated cost of local energy network (LEN) controllers by 2030 is roughly \$3 to \$6 billion.

*Table 6-12
Cost of Controllers to Enable Local Energy Networks*

Technology	Total Units	Units	% Sat	Cost/Unit Low \$	Cost/Unit High \$	Total Cost Low-High \$M
EMS Controllers for Local Area Networks (LEN) on Existing System	464,216	Number of feeders	10	50,000	100,000	2,321-4,642
EMS Controllers for Local Area Networks (LEN) on New Feeders	67,384	Number of feeders	25	50,000	100,000	842-1,685

Summary of Distribution Costs

The cumulative cost for bringing the electrical distribution system up to the technology levels required for the Smart Grid is estimated at \$167 to \$249 billion by 2030. Smart distribution investment will continue well beyond 2030 and will be influenced by the increasing functionality and lower costs of future technology as well as the changing needs of the full array of consumers.

*Table 6-13
Smart Grid Costs for Upgrading the Existing Distribution System*

Technology Group	Total Cost \$M	
	Low	High
Distribution Automation	124,134	177,008
Intelligent Universal Transformers	25,000	25,625
Advanced Metering Infrastructure	15,513	41,915
LEN Controllers	2,321	4,642
Total	166,968	249,190

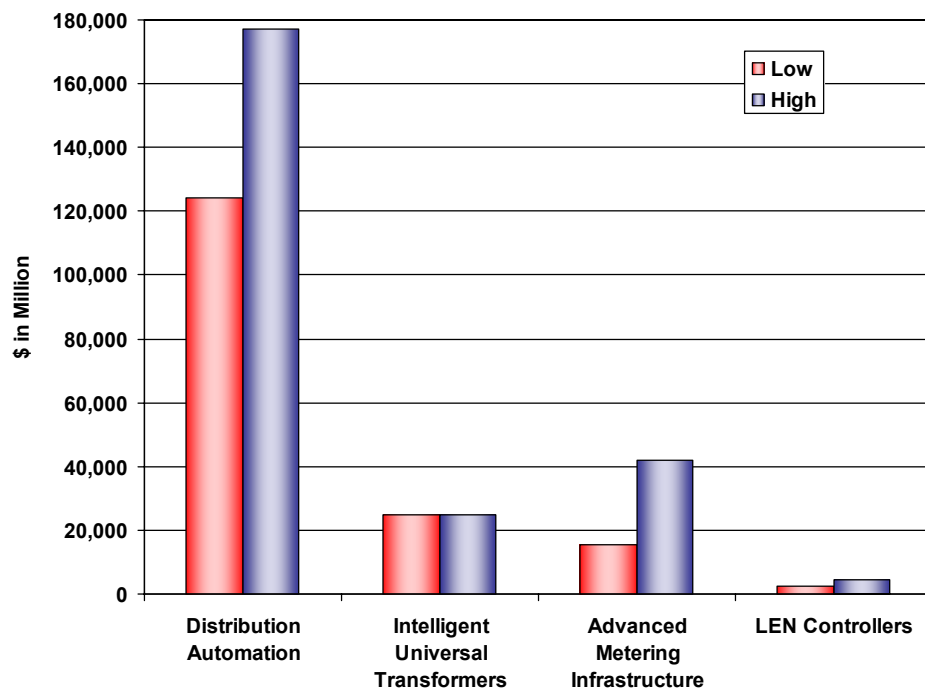


Figure 6-1
Smart Grid Costs for Upgrading the Existing Distribution System

Table 6-14
Smart Grid Costs for Distribution System to Meet Load Growth

Technology Group	Total Cost \$M	
	Low	High
Distribution Automation	38,948	54,059
Intelligent Universal Transformers	25,000	25,625
Advanced Metering Infrastructure	3,365	8,850
LEN Controllers	842	1,685
Total	68,155	90,219

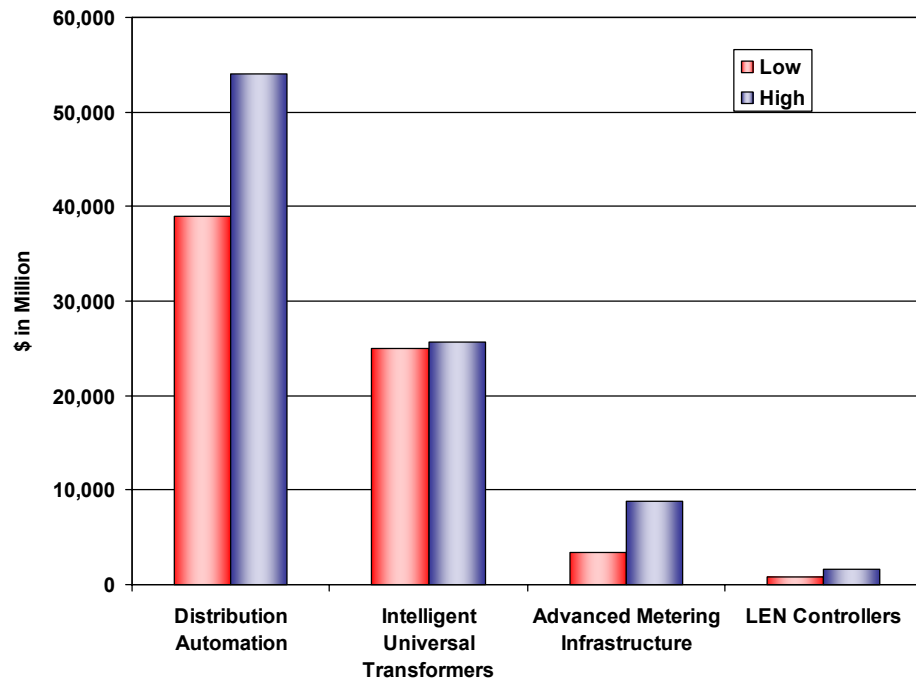


Figure 6-2
Smart Grid Costs for Distribution System to Meet Load Growth

Table 6-15
Total Smart Grid Distribution Costs

Costs to Upgrade the Existing System (\$M)		
	Low	High
Distribution	164,647	249,190
Costs to Embed Smart Grid Functionality While Accommodating Load Growth (\$M)		
	Low	High
Distribution	67,313	90,219
Total	231,960	339,409

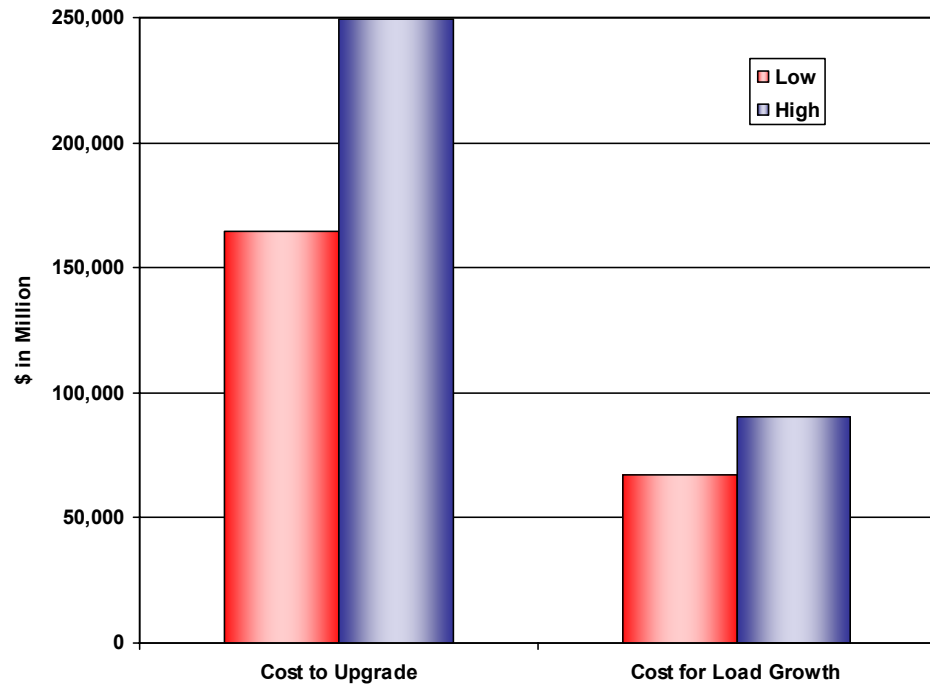


Figure 6-3
Total Smart Grid Distribution Costs

Section 7: Customers

The Smart Grid allows the electricity customer to become fully integrated with the traditional electricity supply system. Such integration began decades ago with commercial and industrial accounts, but with more advanced and lower cost IT and communications technology, it is beginning to gain traction with residential customers. In 2008, FERC estimated 4.7% of the U.S. customers had advanced meters, and that 8% of U.S. customers were engaged in some form of demand response (DR) program. These programs increased the nation's demand-response potential to 5.8% of peak demand by 2008, or more than 40,000MW. DR potential is expected to grow rapidly over the next 20 years as AMI fully saturates the market.

Introduction

There are more than 142 million customers in the U.S., of which 13% represent commercial and industrial accounts. The customer base is expected to grow 16% over the next 20 years to more than 165 million as shown in Table 7-1. However, since most consumer appliances will by then be DR-ready, the actual number of individual communication-connected end nodes will more than double.

Table 7-1
U.S. Electricity Customers

Number of Electric Customers	2007	2030	Load Growth
Residential	123,949,916	143,928,676	19,978,760
Commercial	17,377,219	20,178,151	2,800,932
Industrial	793,767	921,709	127,942
Transportation	750	750	0
Total	142,121,652	165,029,286	22,907,634

Over the next 20 years, integrating the customer into the Smart Grid will enable new functionality to take hold:

- **Increase demand response capabilities** and enable time varying rates to reduce costs, improve load factors, and optimize the economic performance of the grid.

- **Facilitate integration of DER**, including a variety of customer-owned systems, such as rooftop photovoltaic (PV) systems.
- **Integrate the transportation system into the grid** via electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs), which can provide the distributed means for large scale electricity storage for the grid, balance daily load cycles, and substantially reduce the nation's oil dependency.
- **Improve energy management** in the home and commercial buildings, reducing peak demand and improving energy efficiency via intelligent agents.
- **Optimize grid performance** by using the demand-side as a resource for stabilizing the grid, for shaving peak demand, and for reducing the capital investment requirements for peaking generation.

Many of the experts who are studying the Smart Grid are increasingly adopting the view that a truly Smart Grid should require as little consumer participation as possible. The Smart Grid does not require consumer participation to succeed. To date, the cost components of the Smart Grid related to the electricity customer have been limited to the costs of grid integration, and exclude costs borne by the consumer to purchase appliances and devices or in enabling the intelligent devices necessary to minimize their direct participation. While, this study does include the costs of the engineering development costs of DR-ready appliances, it does not include the consumer's purchase of energy efficient or DR ready appliances such as PEVs, air conditioners, washing machines, refrigerators, energy efficient devices, and low-value distributed storage. These costs are excluded for the following reasons:

1. Increasingly the performance criteria for energy efficient devices and appliances are driven by Federal Appliance Efficiency Standards and, to some extent energy efficiency provisions of individual State building codes and standards and not as a result of Smart Grid activities.
2. The hypothesis used in this report is that appliances manufacturers will be able to include DR ready capability in appliances for little or no marginal cost except for some initial expenses included here. The development of advanced appliances is enabling increased on board processing such that DR ready features will evolve with no marginal cost to consumers. Therefore there is no additional cost which should be attributed to the Smart Grid.
3. Decisions to purchase Plug-in Electric Vehicles are completely independent of Smart Grid investments and are not be included in estimating Smart Grid costs.
4. Albeit impossible to predict, there is growing belief that the enabling technologies to engage with consumers and their end use appliances and devices will originate from entities outside the traditional electric utility industry as part of a service bundle. These providers may include entities like internet search firms, software companies, consumer electronics or IT manufacturers and communications providers. As the capital costs associated with these technologies will be minimal and unknown, they are not included in the Smart Grid estimates in this report.

This distinction is shown in greater detail in the Approach section, “What’s In and What’s Out” in Table 3-1. The total cost of the consumer portion of the Smart Grid, as shown in this section, is estimated at \$32-56 billion by 2030.

Cost Components of the Smart Grid: Consumer/Customer Technologies

The key components for the customer portion of Smart Grid costs are listed below:

- Integrated inverter for PV adoption
- Consumer EMS portal and panel
- In-home displays
- Grid-ready appliances and devices
- Vehicle-to-grid two-way power converters
- Residential storage for back-up
- Industrial and commercial storage for power quality
- Commercial building automation

Who Will Bear These Costs?

Costs in this section are labeled as “customer” costs. However, it is not the intent of the authors to imply that the consumer directly bears these costs. Nor are they necessarily costs that will be borne by the utility to integrate them, or a combination of customer and utility costs. These are costs which must be borne by society and paid directly, bundled with other goods and services or otherwise included by the utility in its cost of service. Like the other technologies, these are critical to achieving the vision of a Smart Grid.

PV Inverters

Inverters are microprocessor-based units used to transform dc to ac power that can be used to connect a photovoltaic (PV) system with the public grid. The inverter is the single most sophisticated electronic device used in a PV system, and after the PV module itself, represents the second highest cost. It is also considered the weakest link. Whereas, solar panels are very robust and carry 25-year warranties, inverter warranties have traditionally been in the 5 to 10 year range. Inverter reliability, however, has been trending up.

There are many types of inverters. Some are stand-alone units isolated from the grid and used to support a stand-alone rooftop system; others are grid-tied, in which case the microprocessor circuits are more elaborate and require additional functionality, including lightning protection. Central inverters are used in large applications. Many times they can be connected according to "master-slave" criteria, where the succeeding inverter switches on only when enough solar

radiation is available. Module inverters are used in small photovoltaic systems, such as household rooftops.

A new generation of micro-inverters holds promise to increase PV performance. With current PV design, all solar panels are connected in series, so that if any panel in the series is shaded, it brings down the performance of the entire system. Moreover, for a series module to work, all panels have to have the same orientation and tilt, which limits roof top configuration. The micro-inverter scheme, on the other hand, allows each panel to be connected to its own micro-inverter, increasing overall system performance and providing flexibility for the staggered roof designs of many modern homes. Austin Energy, among others, is testing new micro-inverter designs.

The study team estimated the aggregate cost of inverter integration with 10MW of PV capacity by 2030 at a unit price of \$800-1000/kW at \$8-10 billion.

Table 7-2
Cost of PV Inverters

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Integrated PV Inverter	10,000	kW of distributed PV	100	800	1000	800–1,000

Residential Energy Management System (EMS)

A residential EMS is a system dedicated (at least in part) to managing systems such as building components or products and devices. Residential EMS systems are not typically called “portals” in today’s parlance. Portal is a term commonly applied to a web portal. This subdivides into several components including resident EMS and intelligent home devices (IHD). In addition the system may handle customer preferences and occupancy via a schedule, on-demand, or occupancy sensing automation. The line between a residential management system that handles lighting, family calendars, shopping or replenishment, and an EMS has become fuzzy. While proponents of a dedicated device propose that a homeowner will eventually purchase such a device, we are seeing parallel development of other approaches where the core of the system is a software application bundled on a server located at a third-party data center.

Online energy management portals offer customers insight into their energy usage and automatic management of energy efficiency. Through a central view on a web page, for example, customers can access current energy usage statistics, historical usage patterns, and the amount of carbon dioxide emissions avoided by utilizing a renewable energy source. The portal can also display price signals and tie a customer’s energy consumption and production patterns into their utility’s rate schedule. Current standards developments may also enable effective

aggregation and third party information sharing that will impact the adoption of a residential EMS. As of the writing of this document, preliminary information regarding consumer purchases of advanced residential EMS systems show promise but adoption to date has been low.

These aspects make it difficult to pin the price tag onto the residential EMS. Many components have a dual purpose and exist under separate financial justifications. Consumer reluctance to purchase an EMS may be driven by on-line options that could replace key parts of the functionality of an EMS. These issues could either imply that the cost per customer is low, or the penetration rate is low. However, the end result should be similar regardless of which way we apply this observation.

Based on the plurality of the residential EMS architecture paths, the study team held the residential EMS estimate to 10% of the customer base by 2030 at an average cost \$150 to \$300, yielding a total cost of \$2.2 to \$4.3 billion.

Table 7-3
Cost of EMS Portals

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Customer EMS Portal	143,928,676	Number of	10	150	300	2,159–4,318

In-Home Displays and Access to Energy Information

Providing real-time feedback on energy consumption holds significant promise to reduce electricity demand. Several studies over the past 30 years have evaluated the effectiveness of energy savings from home energy displays of varying sophistication. Most of these studies verified savings between 5% and 15% with a longer-term sustained impact toward the lower end of this scale. Other studies have found that information alone does not appear to be sufficient to achieve appreciable reductions. People need a strong motivation to change, such as compensation, confidence they can change, and feedback that changes they do make are having an impact. In addition this feedback must be easy and trustworthy. As such, most successful approaches provide more frequent feedback, as well as feedback on specific behaviors.

As the Smart Grid unfolds, various methods to provide energy, cost, and environmental information are beginning to emerge. A specific class of stand-alone devices has been utilized extensively and is referred to as the in-home display (IHD). Typically, IHDs present basic information, such as real-time and projected hourly electricity cost and electricity consumption (kWh). Some can display additional information, such as electricity cost and consumption over the last 24 hours, the current month (and/or prior month) consumption and cost, projected usage, monthly peak demand, greenhouse gas emissions, and outdoor

temperature. A similar approach is a component of a prepayment system, also known as a pay-as-you-go system, since these also have a display. The very nature of the pay-as-you-go billing encourages consumers to keep an eye on the display to monitor their usage and know when they will need to replenish their energy account.

In contrast, there are simpler approaches that may not be quantitative. That is, they do not include feedback on electricity consumption or electric demand. Such devices do not require direct attention, but effectively communicate information peripherally. For example, a small glowing ball has been used to indicate a higher electric price or energy demand by changing colors. Other implementations have developed a simple plug-in device with red, green, and yellow lights as simple indicators of energy demand or price.

Small-scale demonstrations have utilized more sophisticated home energy displays. Typically, they provide much greater detail about electricity consumption broken down by different end uses, or circuits, and use richer display graphics. In most cases, these advanced displays are part of a more comprehensive system that may have many features beyond energy management. This makes allocation of the Smart Grid component cost more difficult to pin down since energy management may not be the driving force behind the decision to interact with the device.

Alternative methods to provide energy information to the consumer continue to emerge. As the standards development processes move forward, additional innovations in this area will continue to become available. Some of these products offer an alternative to the dedicated IHD device or at least a subset of functionality. Although the consumer must have a physical means to view the information, the means may already exist in some form such as the PC/laptop, cell phone and PDA. Additional developments might use any products with a consumer facing display as a location to display energy information. This includes appliances, security systems and any new consumer product categories that may be on the drawing board.

Standards resulting from the NIST PAP 10 work may allow product manufacturers the option to include energy information on multi-purpose devices and “other-purposed” devices. This will tend to eliminate or hide the cost making it difficult to identify the cost of access to the energy consumer energy information. This could be accommodated in the cost estimates by indicating that the cost per customer becomes lower over time. This could also be accommodated by indicating that the penetration rate of the stand-alone single-purpose IHD will not ramp up over time due to the alternative methods of information access. With this understanding in mind, the study team estimated 20% of utility residential customers would have an in-home display by 2030. The average cost was estimated at \$20 to \$50 per unit leaving the Total Smart Grid cost estimate at \$1.4 to 2.9 billion for this item.

Table 7-4
Cost of In-Home Displays

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low- High \$M
In-Home Displays	143,928,676	28,785,735	20	20	50	575- 1,439

Grid-Ready Appliances and Devices

Grid-ready appliances do not require truck rolls to retrofit with remote communications and control capabilities. Grid-ready appliances and devices, which are often referred to as “DR-ready,” are manufactured with demand-response (DR) capabilities already built in. The universal entry of grid-ready devices into the marketplace, which is fully anticipated to take shape in the next several years, will lead to ubiquitous demand-response capability.

The average American home has 4.67 appliances per home, with the refrigerator being the most universal (99.8% of U.S. households have a refrigerator based on U.S. Census data). The number of households in the U.S. is projected to reach 143,928,676 by 2030. The study team assumed that the first grid-ready appliances will start to appear in 2011. The penetration of DR-ready appliances is expected to approach 40% over the next 20 years. To account for homes with electric water heating and air conditioning “appliances,” the team increased the average to 5.67 appliances per home. The reader could argue that many water heaters are electric and not every home has AC. There is a balancing argument that the number of appliances per home may also grow, leaving the team comfortable with the 5.67 appliances per home as being a reasonable estimated average.

By using data from AHAM (Association of Home Appliance Manufacturers) for the life expectancy of major appliances, the team used the average life expectancy of 13.91 years for each appliance. By dividing this into the 20-year span of the study, the average appliance would be replaced 1.44 times during this time.

Sales figures indicate that a single year of appliances sales has trended toward 10% of the current installed base. This number includes both new construction and replacement sales. Since we are using the projected number of households for the year 2030 which includes new construction, the replacement from appliance life-expectancy was used against the year 2030 households projection to avoid double counting. The additional cost to incorporate grid-ready functionality into future appliances is estimated at \$10 to \$20 per unit for the first generation, but declining to zero within 10 years as the grid-ready design becomes standard. Rather than accounting for engineering cost separately, this was included with the component costs per appliance. The final number should indicate the cost to

the consumer which includes other costs calculated from the materials and production costs.

The team estimated that in the year 2011, the total consumer cost per appliance would be \$40. This appears as higher costs during the first several years. Both the engineering cost and the component cost are assumed to reduce over time as is the norm in a product development cycle. In the future, the grid-ready design is expected to become part of a standard appliance design. Furthermore, the team assumed that the appliances will have communication technology built in that is justified for other non-energy usages and additional consumer benefits. This should make this cost become negligible after 10 years.

Penetration by 2030 may be limited by consumer model selection and the fact that certain appliance products (such as cooking and refrigeration) may not be nearly as appropriate as others for grid messaging or demand management. Therefore, the study shows the penetration starting to level off as it approaches 40%. The assumptions used by the study team are summarized in Table 7-5, and indicate the expected non-linear penetration and costs as smart-grid appliances enter the market.

Table 7-5
Assumptions of Grid-Ready Appliance Costs

Grid-Ready Appliance Costs	Value	Notations
Total U.S. Households	143,928,676	Includes projected growth to 2030 (1)
Total appliances per household	4.67	Including electric HW and AC (2)
Penetration by 2030	38%	See chart for ramp up (3)
Appliance Life Expectancy	13.91 yrs	Averaged from cooking, cleaning, food preservation (4)
Rate of replacements	1.44	In 20 years each appliance will be purchased 1.44 times (5)
Estimated Total Appliances Purchases	1,173,442,029	58,672,101 per year average (6)
Total Cost	\$230,531,663-\$412,354,482	Assumes penetration ramp up starting between 0.2% and .5% in 2011 (7)
(1) U.S. Census information (2) Extrapolated from U.S. Census information (3) Penetration estimated. Note that Smart Grid appliances and other products will ramp up. Estimated from averaging a number of informal sources (that may be changing daily). (4) By using data from AHAM (Association of Home Appliance Manufacturers) for the life expectancy of major appliances, the team used the average life expectancy of 13.91 years for each appliance. (5) Simple application of the average life expectancy of 13.91 years for each appliance and dividing this into the 20-year span of the study, the average appliance would be replaced 1.44 times during this time. (6) Simply the application of the other numbers and averages to determine the number of appliances purchased (conversation with AHAM staff). (7) The ramp-up rate of products containing Smart Grid enablements. As in (3) above, the ramp rate is arguable and could shift widely over the time period estimated. Currently, the ramp-up happens at an initial pace that is defensible at this point in time. Most manufacturers are not willing to share a lot of sales and projected sales of new and unannounced product models.		

Variables used to select the cost range are largely dependant on two factors. The first is the cost of the engineering and components added to the appliances. The second significant factor is the rate of market penetration of the Smart-Grid enabled appliances. Since the component cost is projected as being higher in the early years, as diagrammed in Figure 7-1, faster deployment can push the total cost of Smart Grid appliances upward. However, an earlier drop in components cost due to higher volume might counteract this to some degree bringing the cost

of common appliance Smart Grid components down earlier in the cycle. The range of cost of grid-read appliances was estimated between \$230 to \$412 million.

Table 7-6
Cost of Grid-Ready Appliances

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low- High \$M
Grid-Ready Appliances	143,928,676	Number of	38%	230	412	230-412

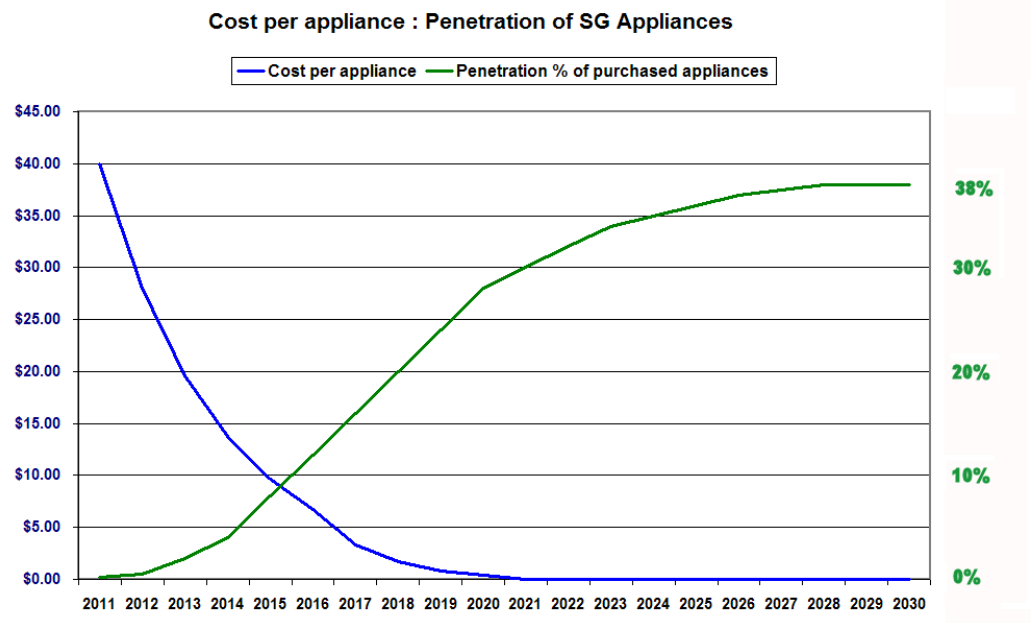


Figure 7-1
Appliance Cost and Penetration

Plug-in Electric Vehicle Charging Infrastructure and On-Vehicle Smart Grid Communications Technologies

Plug-in electric vehicles (PEVs) are defined as any hybrid vehicle with the ability to recharge its batteries from the grid, providing some or all of its driving through electric-only means. Almost all of the major automotive manufacturers have announced demonstration or production programs in the 2010-2014 timeframe, and their announced vehicles feature all-electric, plug-in hybrid-electric and extended-range electric vehicle configurations. Notable and earliest

introductions among these are globally targeted production vehicles from General Motors (Chevrolet Volt, extended-range EV) and Nissan (Leaf, battery-only EV). It should also be noted that Tesla remains the only manufacturer today producing a two-seater roadster and continues to work on their lower-priced, family (Model S) sedan.

EPRI is deeply involved in developing and demonstrating on- and off-vehicle PEV to Smart Grid connectivity technologies. Automotive manufacturers are bringing their early generations of PEVs designed for grid rechargability with uni-directional electric power flow capability (from grid to vehicle). These first generation of vehicles will be relying on the consumer inputs via in-vehicle interactive touch panel display or through cellular/Telematics connectivity, to program vehicle charging, input pricing or other information related to on-board energy management. Given this state of technology on board the PEVs, the initial impetus for any type of demand response and load control as well as critical peak pricing program implementation has been on the off-board “charging” station equipment. The technical term is electric-vehicle supply equipment (or EVSE), given that the off-board equipment is just a glorified 240 Volt outlet while the actual AC/DC power conversion and energy management actually occurs on-board the PEVs. The most predominant costs associated with the Smart Grid infrastructure capability will, therefore, be in developing Smart Grid to PEV and Smart Grid to “charging” station (aka, electric vehicle supply equipment or EVSE) connectivity and communications.

All applications which may provide reverse flow power capability such as vehicle-to-grid (V2G) are unproven. Their impact on battery durability, utility/automotive/consumer acceptance, and economics are yet to be demonstrated. In addition, it is uncertain what services they will enable and whether policies and incentives will be needed to bring them to reality. V2G, therefore, remains an R&D agenda item of several automotive manufacturers, EPRI, some ISOs/RTOs, and several R&D institutions. It is, however, too early to predict the direction and magnitude of this technology’s installed base in the near future.

In terms of load management or time shifting of the load due to PEV charging, both utilities and automotive manufacturers have agreed to jointly pursue standardization activity that will enable the PEVs to act as just another appliance on the AMI or HAN. Two activities within SAE, under J2836 (use cases) and J2847 (data specification) with extensive automotive and utility participation, are in the process of defining the requirements for PEV to Smart Grid communications, which will enable the PEVs to be utility-controllable distributed resources for load shifting, demand response, and pricing-signaling purposes. ZigBee Alliance and HomePlug Alliance have created the Smart Energy Initiative, which is crafting the Smart Energy 2.0 (SE2.0) specification for AMI and HAN applicability. SAEJ2836/J2847 and SE2.0 teams are working together to coordinate the data exchange requirements between Smart Grid and PEVs. A draft Marketing Requirements Document (MRD) and Technical Requirements Document (TRD) are currently being refined for late 2010 ratification. SE2.0 and J2847 are expected to define a consistent set of data

specifications for the charging load of the PEVs to be controllable by the same utility load management systems that determine demand response and load control signals for other loads, such as air conditioners, smart thermostats, or other smart appliances. The SAEJ2836 use cases include enabling PEV owners to enroll into utility demand response, load control and special incentive pricing programs and then program their vehicles to accept or reject utility requests for participating in demand response, load control and critical peak pricing-related events.

For the first generation of PEVs, the technology options for integrating PEVs with the Smart Grid will reside off-board, in the form of the closed, proprietary networks of charging station operators such as Coulomb Technologies, ECOtality, and Silver Spring Networks. Whereas significant public funding to the tune of \$300M through stimulus awards from federal government and state and local authorities has been directed towards focused regional charging infrastructure build-out, the focus has been on enabling PEV technology adoption in early adopter markets, rather than on scalability and cost competitiveness of these technologies longer term.

EPRI's collaborative research with the automotive industry indicates that for PEVs to be widely deployed, the infrastructure overhead for them would need to be reduced to "minimal to none," with each PEV carrying its own required technology on-board that can connect to the nearest Smart Grid node. It would use either AMI/HAN to connect to the Smart Grid through the "front-end" or the on-board Telematics-based technology to connect through the "back end" to the utility back office systems, and to meter data management systems through standardized server- to-server communications.

To this end, EPRI envisions the PEV manufacturers to quickly integrate the standards-driven communication technologies on-board the PEV. The only significant costs for "Smart Grid-enabled" PEVs will, therefore, be the cost-plus for incorporating the communications hardware necessary to send/receive data from the utility based on applicable standards. The automotive and utility industries have agreed for PLC- (power line carrier-) based wired interface to be the physical interface between the PEV and the AMI/HAN, with the PLC(HomePlug AV or IEEE1901 are the currently adopted technologies) transceiver chipset and associated Smart Grid communications "application layer" software with requirements defined by SAEJ2836/J2847 and SE2.0, residing on-board. That would include a PLCto X bridge residing off-board, with X being the transport layer of the AM I/HAN network, which also implements SE2.0-based messaging as the application layer.

The per-vehicle cost overhead for PLC transceiver is about \$20 per vehicle in the near term, reducing to \$10 per vehicle longer term, as PLC is already a very widely deployed technology. On the PLC to X bridge aspect, the X in most cases is ZigBee, but WiFi (802.11x-based) is also rapidly emerging as the HAN contender. The per-unit PLC/ZigBee or PLC/WiFi chipset prices vary between \$10 and 20 per unit as well. Given that there are likely to be 1.2 charging stations long term for every PEV sold, the per-PEV PLC to X bridge costs will run to

\$12 to \$24. Therefore, the per-PEV infrastructure costs will run to between \$25 and 50 for long-term and short-term volumes respectively. Assuming 2030 PEV installed base volume to be about 10 million vehicles, the cost of deploying Smart Grid infrastructure will approach \$250 million (\$25 per unit times 10 million vehicles) in 2030.

Table 7-7
Cost of Vehicle to Grid Converter

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low- High \$M
Vehicle to Grid Power Converter	30,000,000	Number of vehicles	50	300	500	4,500- 7,500

Communication Upgrades for Building Automation

Today, over one-third of the conditioned and institutional buildings in the U.S. have some form of energy management and control systems installed (EPRI 101883). Automated demand response (ADR) can be accomplished by communicating to advanced building energy management systems using an Internet-communicated signal or some other form of direct link. Legacy systems deployed today lack this capability. Open automated demand-response (Open-ADR) involves a machine-to-machine communication standard that provides electronic, Internet-based price and reliability signals linked directly to the end-use control systems or related building and automated control systems (EPRI 1016082). The building automation system is pre-programmed to reduce load according to the messages it receives, and it may also provide real-time energy consumption information back to the utility or service provider.

Employing Open-ADR presumes the building has an advanced EMS system. There are two cost components that enable the building to respond to DR signals. The first is enable the building's EMS to receive the DR signals. In some cases, this might mean upgrading the software, and in other cases, this might mean installing a "simple client" whose only purpose is to receive the DR signals and pass them on to the EMS system. One of the features of Open-ADR is to allow very simple and inexpensive clients to be built that can interface to existing EMS systems via dry-relay contacts. Dry relay contacts seem to be the near-universal interface mechanism for EMS systems.

The second and perhaps largest cost component is the programming of load control strategies in the EMS. The cost is primarily one of manpower that involves audits of loads in the facility and specialized knowledge of how to convert the EMS to implement load control strategies. Auditing building use and load characteristic is not a trivial exercise. In this regard, the simple response levels sent as part of an Open-ADR signal can be used. In many cases, it is more

convenient for the facility manager to think in terms of “normal, moderate, and high” response levels instead of prices or specific dispatch commands. Also, it is not insignificant that if the engineers set up their load control strategies based upon simple levels, then they can more easily move between different programs without the need to reprogram their EMS system.

The study team estimated that by 2030 some 5% of the 20,178,151 commercial buildings would be upgraded to the level of complete energy automation at a cost of \$5,000 to \$20,000 per building. The total Smart Grid cost is estimated between \$5–20 billion.

*Table 7-8
Cost of Communication Upgrades for Building Automation*

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low– High \$M
Communication Upgrades for Building Automation	20,178,151	Number of buildings	5	5,000	20,000	5,045-20,180

Electric Energy Storage

Advanced lead-acid batteries represent the most prevalent form of electric energy storage for residential, commercial and industrial customers wanting to maintain an uninterruptible power supply (UPS) system. In the future stationary lithium-ion batteries may also be deployed for use in consumer premises.

As shown in Table 7-9, commercial and industrial systems can supply power for up to 8 hours at 75% efficiency, and maintain performance through more than 5000 cycles. Residential versions typically involve two hour duration at 75% efficiency and 5000 cycle performance.

*Table 7-9
Electric Energy Storage Options for Customers*

Application	Technology option	Capacity (MWh)	Duration (hours)	Efficiency %	Total cycles	Cost \$/kW
Residential	Advanced lead-acid	0.8	8	75%	5000	2300-2400
Commercial & Industrial	Advanced lead-acid	10	2	75%	5000	2200-2400

Both standby and online UPS technologies are available. The online UPS is ideal for environments where electrical isolation is necessary or for equipment that is very sensitive to power fluctuations. Although once previously reserved for very

large installations of 10 kW or more, advances in technology have permitted it to now be available as a common consumer device, supplying 500 watts or less. The online UPS is generally more expensive but may be necessary when the power environment is "noisy" such as in industrial settings, or for larger equipment loads like data centers, or when operation from an extended-run backup generator is necessary.

In an online UPS, the batteries are always connected to the inverter, so that no power transfer switches are necessary. When power loss occurs, the rectifier simply drops out of the circuit and the batteries keep the power steady and unchanged. When power is restored, the rectifier resumes carrying most of the load and begins charging the batteries, though the charging current may be limited to prevent the high-power rectifier from overheating the batteries and boiling off the electrolyte.

The main advantage to the on-line UPS is its ability to provide an electrical firewall between the incoming utility power and sensitive electronic equipment. While the standby and Line-Interactive UPS merely filter the input utility power, the Double-Conversion UPS provides a layer of insulation from power quality problems. It allows control of output voltage and frequency regardless of input voltage and frequency.

The study team estimated that by 2030 roughly 1.8 GW of on-site back-up storage will be installed in commercial and industrial facilities at a unit cost of \$2300 to 2400/kW. An additional 2.8 GW of battery storage for residential backup applications will be installed at an average unit cost of \$2200 to 2400 kW.

*Table 7-10
Cost of Electric Energy Storage*

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low-High \$M
Integrated PV Inverter	10,000	kW of distributed PV	100	800	1000	8.0-10.0
Consumer Energy Management System	143,928,676	Number of	10	150	300	2,159–4,318
In Home Displays	143,928,676	Number of	20	50	100	1,439–2,878

Summary of Customer Costs

The cost to bring the customer interface of the electric infrastructure up to Smart Grid performance levels so that it can support a broad array of customer services—ranging from DR-ready appliances to V2G charging—is estimated at \$24 to \$44 billion, as shown in Table 7-11. This cost does not include the sizeable investment that will be made by customer in appliances, PHEVs, HVAC equipment, and the like.

Table 7-11
Smart Grid Costs for Customers

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low– High \$M
Integrated PV Inverter	10,000	kW of distributed PV	100	800	1000	8.0-10.0
Consumer Energy Management System	143,928,676	Number of	10	150	300	2,159–4,318
In Home Displays	143,928,676	Number of	20	50	100	1,439–2,878
Grid-Ready Appliances	143,928,676	Number of	40%	10	20	222–443
Vehicle to Grid Power Converter	30,000,000	Number of vehicles	50	300	500	4,500–7,500
Communication Upgrades for Building Automation	20, 178,151	Number of buildings	5	5,000	20,000	5,045–20,180
Industrial & Commercial Storage for Backup	1,800,000	kW	100	2,300	2,400	4,140–4,534

Table 7-11 (continued)
Smart Grid Costs for Customers

Technology	Total Units	Units	% Sat	Cost/ Unit Low \$	Cost/ Unit High \$	Total Cost Low- High \$M
Residential Storage for Backup	2,800,000	kW	100	2,200	2,400	6,160- 6,720
Ongoing System Maintenance						
Total Cost Customer						23,672- 46,368
Allocated to Existing Customers						20,386- 39,932
Allocated to New Customers						3,286- 6,436

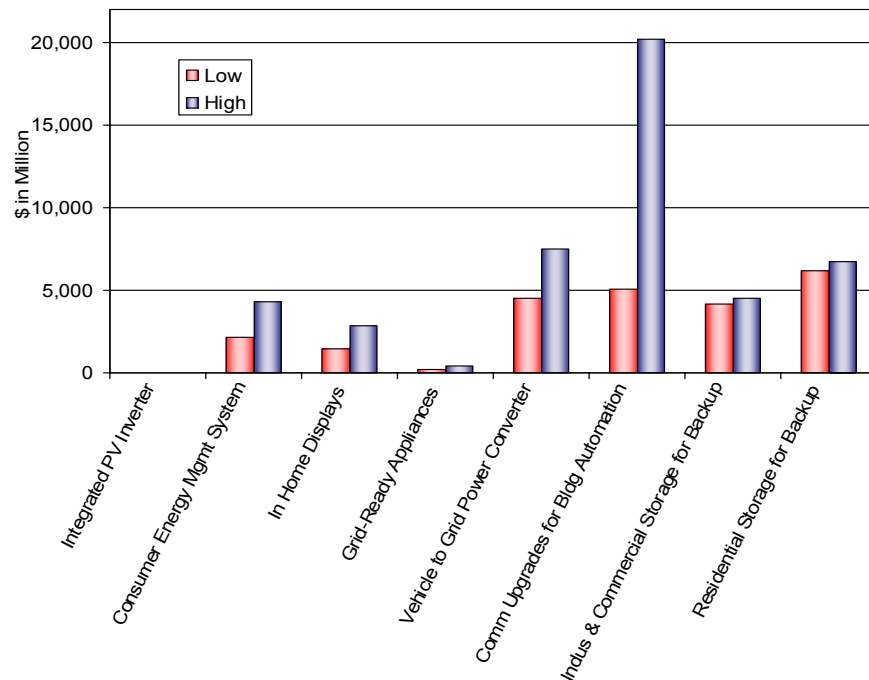


Figure 7-2
Consumer Costs for a Smart Grid



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Appendix A: Notes Pertaining to Table 4-5: List of Smart Grid Benefits

Facilitating Plug-In Electric Vehicles (PEVs)

Hi Band Estimate – EPRI's Prism analysis estimates a potential CO₂ emissions reduction in 2030 of 9.3% as a result of electricity displacing gasoline and diesel to fuel a substantial portion of the vehicle fleet. EPRI bases this estimate on the assumption that plug-in electric vehicles (PEVs) are introduced to the market in 2010, consistent with product plans of many automakers, and the rapid growth of market share to almost half of new vehicle sales within 15 years. Net emissions reduction estimates from the increasing market share of PEVs are based on research by EPRI and others (EPRI/NRCD, 2007), factoring vehicle miles traveled, carbon savings from gasoline not burned, and the trend for the electric system to become “cleaner” – i.e., for an increasing share of power generation to emit less or no CO₂.

EPRI Prism analysis assumptions:

- 100 million PEVs in the fleet by 2030; and
- Fraction of non-road transportation applications (e.g., forklifts) represents three times the current share by 2030.

PEV Low Band – The PEV low band used the results of the EPRI-NRDC study from 2007 and, somewhat arbitrarily, attributed up to 20% of the carbon savings to the presence of a Smart Grid. The reasoning was that a Smart Grid is an enabling factor, but not the sole determining factor, in the market growth of PEVs. PEV-to-Smart Grid interface-related incremental costs, which run about \$25 to \$50 per vehicle (on- and off-board, \$50 short term, \$25 long term, and only include the PLC and PLC/X interface chipset BOM costs). So the incremental cost estimate is \$250 million.

Facilitating Electrotechnologies

The 2009 analysis estimates a potential CO₂ emissions reduction in 2030 of 6.5% as a result of electric technologies displacing traditional use of primary energy consumption for certain commercial and industrial applications. Electrotechnology research (EPRI/ELEC, 2009) indicates that there are applications through which net reductions in CO₂ emissions can be achieved.

This projection is based on replacing significant use of direct fossil-fueled primary energy with relatively de-carbonized electricity for a range of possible applications, e.g., heat pumps, water heaters, ovens, induction melting, and arc furnaces. It is assumed that 25% of these electro technologies are facilitated by the Smart Grid. A total of 4.5% of primary energy supplied by fossil fuels is replaced by electricity by 2030.

Facilitating Renewable Energy Resources

Hi Band Estimate – EPRI's 2009 analysis estimates a potential CO₂ emissions reduction in 2030 of 13% as a result of substantially increased deployment of renewable generation facilitated by the Smart Grid. This assumes the penetration of diverse renewable generation resources based on consideration of existing and potential state and federal programs, cost and performance improvements, and grid integration challenges. This assumption corresponds to 135 gigawatts (GW) by 2030 consisting of ~100 GW new wind; ~20 GW new biomass; and ~15 GW other technologies including solar. The average new generation over 20 years will be equal to 67.5 GW corresponding to a reduction in 3.41 Billion tons of CO₂ at \$50 per ton or \$172 billion.

Low Band Estimate – The renewables low band estimate was based on 100 additional GW of renewable capacity. Of that, 50 GW was assumed to be wind power. Assuming a 61% load factor, 267 billion kWh of additional energy would be by wind. The study attributed 50% of the realization of this energy from wind to the resolution of the intermittency challenge of wind, and then further, attributed up to 50% of the credit for resolving the intermittency challenge to the presence of a Smart Grid. The rationale used was that Smart Grid is not the sole criterion for such large-scale wind integration, but it is a critical component. The study then applied the estimated CO₂ intensity of generation in 2030 to get the 37 MMtons figure.

Table A-1

Environment Benefits From Renewables, PEVs and Electrotechnologies: High Band Estimates

	Technology	% Savings	20-Year Savings (@ ramp 0 to 100%)		
			Total	%Attribute to Smart Grid	\$ @ \$50/Ton
Gross CO ₂ in 2030 263,900,000 Million Metric Tons	Additional Renewables	13	3.431E+09	100	1.72E+11
	PEV	9.3	2.454E+09	100	1.23E+11
	Electrotech	6.5	1.715E+09	25	2.14E+10

Table A-2

Low-Band Estimates of PEVs and Renewables (EPRI)

	Million Tons Co ₂ (2030)		Total (over 20 years)		\$B @ \$50/Ton	
	Low	High	Low	High	Low	High
Renewables	19	37	190	270	9.5	18.5
PEVs	10	60	100	600	5.0	30.0

Table A-3

Value of PEVs: High Band

			\$B	
			Low	High
Value of PEVs as a grid support technology*	50% of 30 million vehicles in 20 years	\$1,500 per vehicle	11.3	11.3
*Wellinghoff, 2008				

Expanded Energy Efficiency

EPRI provides estimates of benefits of expanded energy efficiency not included in its 2004 report in a subsequent study (EPRI 1016905). This is shown in Table A-4.

Table A-4

Value of Expanded Energy Efficiency

Type	Billion kWh (2030)		Value \$ (@ 7¢/kWh)		Co2 Reduction Mill. Metric Ton		Value @ \$50/Ton	
	Low	High	Low	High	Low	High	Low	High
Continuous commissioning	2	9	140M	630M	1	5	50M	250M
Energy efficiency benefits from demand response	0	4	0	280M	0	2	0	100M
Feedback	40	121	280M	847M	22	68	1100M	3400M
Total	42	134	420M	1757M	23	75	1150M	3750M

Related T&D capital savings can be calculated using the following assumptions

- 25% Load Factor and T&D Savings \$ 800/kW = 2030 savings range from \$ 1B to \$ 3B

AMI Benefits

Table A-5
Edison SmartConnect™ Cost Benefit Information and U.S. Estimate

Benefits	Amount (\$M)
Meter Services	\$3,909
Billing Operations	187
Call Center	96
Transmission & Distribution Operations	92
Demand Response – Price Response	1,044
Demand Response – Load Control	1,242
Conservation Effect	828
Other	39
Total Benefits	\$7,437

Southern California Edison (SCE) filings to the California Public Utilities Commission (CPUC) Proceedings: D.08-09-039, A.08-06-001; A.08-07-021 estimated benefits for several AMI attributes over a 20-year period including: Meter Services = \$3,909 million; Billing Operations = \$1,187 million; and Call Center = \$96 million. Estimate made using SCE estimates of \$4,874,890 customers and total U.S. estimated customers in 2030 of 142,121,652.

Table A-6
Southern California Edison Company Estimates of AMI Attributes

	\$	\$/Meter	Potential Benefit	Estimated Benefit
Meter services	3,909,000,000	801.8642	1.13962E+11	91,169,817,193
Billing operations	187,000,000	38.35984	5,451,763,819	4,361,411,055
Call center	96,000,000	19.69275	2,798,766,453	2,239,013,162
Total SCE meters	4,874,890			
Total U.S. meters	142,121,652			

Avoided Generation Investment from EE and DR

The Brattle Group estimates (Brattle, 2008) for the period 2010 to 2030 of avoided generation cost investment due to energy efficiency and demand response to be between \$129 billion and \$242 billion.

Table A-7

Avoided Generation Investment from Energy Efficiency and Demand Response (Brattle, 2008)

	Low	High
(Avoided) generation investment due to EE/DR	(192)	(242)

Energy Storage Benefits

Table A-8

Storage Benefits by Attribute (20 years) (EPRI 1017813 and Sandia, 2010)

Type	\$Million	
	Low	High
Improved Asset Utilization		
Electric Energy Time Shift	4,936	7,367
Electric Supply Capacity	3,239	8,908
Load Following	16,354	32,561
Area Regulation	1,236	1,519
Electric Supply Reserve Capacity	1,915	2,634
Voltage Support	497	1,326
Transmission Support	221	937
Transmission Congestion Relief	19,745	33,743
Total	48,142	88,995
T&D Capital Savings		
T&D Upgrade Deferred	8,257	21,421
Renewables Capacity Firming	6,483	17,828
Wind Integration – short	958	2,865
Wind Integration – long	7,662	22,911
Total	23,360	65,024

Table A-8 (continued)
Storage Benefits by Attribute (20 years) (EPRI 1017813 and Sandia, 2010)

Type	\$Million	
	Low	High
Electricity Cost Savings		
TOU Energy Cost Management	96,855	139,502
Demand Charge Management	18,245	58,976
Total	115,100	198,478
Reliability		
Substation On-Site Power	55	791
Reliability	1,731	19,774
Power Quality	700	21,026
Total	2,485	41,591
Environmental		
Renewables Integration	9,871	14,733
Total	9,871	14,733
Total All Storage	198,959	408,821

Table A-9
Distributed Generation Transmission Capacity Assumptions

Distributed Generation	Core Value
Capacity per participating customer (kW)	3.0
Grid connected PV systems	70000
Penetration growth rate	10.0%
Capacity factor	15.0%
Capacity reduction per kW – Transmission	0.45 kW
Total reduction 2010 – 2030	\$27 Billion

Electrification Energy Benefits

Table A-10

Reduced Net Energy Required by Electrification (EPRI 1014044 and 1018871)

	High Case	Low Case
2030 decrease in quadrillion BTUs	5.32	1.71
2010-2030 decrease in quadrillion BTUs	53.2	17.1
Value @ \$6.000 per million BTUs	\$319.2M	\$102.6M

Table A-11

Electric Sector Carbon Dioxide Emissions (AEO, 2009 Updated)

	Million Metric Tons is 2030
Petroleum	41
Natural gas	365
Coal	2222
Other*	12
Total	2639

*Includes emissions from geothermal power
and non-biogenic emissions from municipal waste.

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