ILLINOIS STATEWIDE SMART GRID COLLABORATIVE:

Collaborative Report

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Report Compiled by

EnerNex
CORPORATION

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Facilitator’s Preface

EnerNex was privileged to serve as the Facilitator of the Illinois Statewide Smart Grid Collaborative (ISSGC) and to prepare the Collaborative Report for submission to the Illinois Commerce Commission. To put this Report into context, EnerNex offers its perspective on the conditions and drivers that have resulted in an unprecedented level of activity in the United States and abroad to modernize the electrical grid. We also introduce some of the challenges faced by state regulators as they consider if, when, and how a smart grid should be implemented in their jurisdiction.

Illinois has embarked on a thorough consideration of smart grid issues at a momentous time in the history of the US electricity system. Sometimes called "the world's largest machine," this system encompasses more than 5,000 large central station generating plants connected together by 157,000 miles of high-voltage transmission lines and millions of miles of distribution wires. Except for its gargantuan size, today's centralized system has not changed fundamentally since its inception well over a century ago. While there have been continual technological advances, it has not undergone the digital transformation that characterizes many industries, and the grid remains largely a one-way system of providing electricity to businesses and households on demand. Those demands have continued to rise, with total residential usage up 40% since 1990 in Illinois, and average usage per Illinois household up 20% in that period.[1] The percentage of total US energy consumption devoted to electricity was 10% in 1940 and 25% in 1970.[2] Today it is 40% and still growing, with plug-in electric vehicles about to enter the mass market. If power production were an infinite resource without potential "negative externalities" like environmental consequences, if transmission lines were easy to site wherever needed, and if costs were not an obstacle, the system could continue on the same trajectory for a long time to come. But, that path appears increasingly unsustainable, and several converging trends point to a new direction for America's energy future, one that poses new challenges and new opportunities for consumers, utilities, and regulators.

As the electrification of our economy and the number of electrical devices we use to support a modern lifestyle grow each year, the electricity infrastructure we often take for granted is aging. Increasing numbers of critical components in the electric power generation and delivery system remain in service well beyond their design life and are being stretched to the limits of their capacity. While overall electricity demand grew by more than 25% since 1990, construction of transmission facilities fell by 30% in that period.[3] The resulting congestion has increased market electricity prices and raised line losses from 5% of electricity transmitted in the 1970s to 7% today.[4] The threat of system failures – and their potential cost to consumers and the economy -- is on the rise.

The average age of power plants is more than thirty years; however, economic constraints and environmental concerns limit the construction of large new central station generators.

[1] Residential usage grew from 29,000,534 MWh in 1990 to 40,744,127 MWh in 2008; average usage per household grew from 7,418 kWh to 8,867 kWh; source: Illinois Commerce Commission Comparison of Electric Sales Statistics.

[2] See US Energy Information Administration "2009 Annual Energy Review"

[3] See US DOE Office of Electricity Delivery and Energy Reliability "Overview of the Electric Grid"

[4] See http://www.eia.doe.gov/cneaf/electricity/st_profiles/us.html and http://www.pi.energy.gov/documents/TransmissionGrid.pdf,

Construction and equipment costs continue to climb, and a study by the Brattle Group estimates a total cost of at least $1.5 trillion dollars over the next twenty years to provide needed upgrades, new power plants, and expansion of capacity, including $880 billion in transmission and distribution investment.[5]

At the same time, concern about carbon dioxide and other emissions contributing to global climate change is producing public demands for alternatives to fossil-fueled electricity. Electricity production creates almost 40% of the nation's output of "greenhouse gases" -- far more than produced by the transportation sector.[6] Policy in many states has begun to shift towards promoting renewable energy resources, which have been expanding rapidly in recent years. The installed capacity of wind power and solar power in the US grew by 40% in 2009 alone.[7] The growth of state Renewable Portfolio Standards over time can be anticipated to keep these resources at the forefront of new energy development, as Illinois and many other states strive to use clean energy to improve the environment and create jobs. While non-hydro renewable energy currently supplies less than 4% of US electricity needs, the US Department of Energy (DOE) projects potential for more than 20% of US electricity to be generated using these sources within the next twenty years. However, wind and solar power are variable and distributed resources; bringing them to market and integrating them into the resource mix at high penetration levels is a challenging task.

The economic slowdown in recent years has put the brakes on demand for electricity and market electricity prices. It is not clear how long this trend will continue but, as EPA administrator Lisa P. Jackson has said, "The energy that most effectively cuts costs and protects us from climate change… is the energy that's never used in the first place."[8] Around-the-clock energy efficiency has become a key goal for Illinois and for the nation. Reducing peak demand for electricity is a particularly effective way to cut electricity system costs in both the short and long terms. New technology and new market mechanisms are beginning to provide the means for individual customers of all sizes to participate in demand response programs, responding to price or other signals to cut usage during periods of high demand. But many barriers remain to the full market integration of demand response that is necessary to allow "negawatts" to compete with megawatts.

In the post-9/11 age, grid security -- both cyber security and physical security -- also is a growing concern for system operators and planners, as well as customers. In legislation such as HR5026 -- the Grid Reliability and Infrastructure Defense (GRID) Act -- Congress has indicated that it will mandate specific measures to protect critical electric infrastructure. National mandates and technical best practices being developed by the National Institute of Standards (NIST), DOE, and others will need to be built into any new system.

[5] See: http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf

[6] http://www.eia.doe.gov/oiaf/1605/ggrpt/

[7] See 2009 DOE Wind Technologies Market Report, http://eetd.lbl.gov/ea/ems/reports/lbnl-3716e.pdf and Interstate Renewable Council US Solar Market Trends 2009, http://irecusa.org/wp-content/uploads/2010/07/IREC-Solar-Market-Trends-Report-2010_7-27-10_web1.pdf

[8] http://yosemite.epa.gov/opa/admpress.nsf/0/5B2E6D9AA8D257758525760200686356

In the context of these facts and trends, states across the US are making decisions about deployment of resources to modernize their electric systems to meet 21st century needs. Long-term federal energy policy remains unsettled, but in 2007 Congress established "smart grid" development as a national policy goal and directed the identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services. It also instructed each state to consider requiring electric utilities to contemplate smart grid solutions when planning grid modernization, and to consider allowing cost recovery of smart grid investments.[9]

Congress also recognized that a focused national approach would be needed to achieve interoperability -- the ability of all smart components to seamlessly communicate and interact. With myriad devices, manufacturers, systems and applications, uniform national standards and protocols are essential. Responsibility for coordination of the standard-setting process was assigned by Congress to the National Institute of Standards and Technology (NIST). NIST initiated the Smart Grid Interoperability Panel (SGIP), a public-private partnership that has taken on this enormously complex multi-year project, and has developed and is executing seventeen specific Priority Action Plans (PAP's) to address specific standards issues to be resolved. In addition, more than seventy specific standards have been identified for analysis as to how they should be applied to various aspects of electric power infrastructure.

There is little doubt that a widely deployed smart grid would lead to more efficient energy use, and could eventually transform the system from a centralized network run by the electricity producers, distributors and system operators to a more decentralized consumer interactive network. Adding digital sensors and remote controls to the transmission and distribution system would extend asset lives and make service more reliable. A smarter system would be better able to cope with new sources of renewable power and large numbers of electric vehicles. Smart meters could provide information to consumers about their usage in near real-time and allow utilities to monitor and control their networks more effectively.

However, expected costs for smart grid deployment are substantial, the barriers are significant, and the anticipated benefits will not accrue to all customers equally. In assessing its grid modernization policies and its treatment of smart grid investments, each state must take into account a host of local issues, including regional and local economics, energy sources, energy market structure, consumer preferences, and impacts of geography and demographics. Affordability of utility service to consumers and equitable treatment of all ratepayers are always key issues for regulators and those characteristics are essential to public acceptance of any changes in utility service or policies. The process by which utility regulators determine what investments are reasonable and necessary, who bears the costs and realizes the benefits, and how those costs will be recovered, must be perceived as fair and implemented consistently.

Decisions about smart grid deployment are the responsibility of state regulators, but Congress appropriated $4.5 billion to modernize the electric grid as part of the 2009 American Recovery

[9] For a bill summary of the Energy Independence and Security Act of 2007, as well as full text, see: http://www.govtrack.us/congress/bill.xpd?bill=h110-6

and Reinvestment Act (ARRA). More than $2 billion of this amount has been allocated to grants for advanced metering projects. Many states have begun to assess the value and costs of smart grid deployment and some have begun actual deployment.[10] Approximately 16.5 million advanced meters have been installed in the US to date (11% of all meters) with about 34 million additional meters approved by state regulators.[11]

Not all advanced metering projects have gone smoothly and without controversy. In California, Texas, Boulder and Baltimore, problems have been reported by consumers and deployment missteps have occurred. Many of these problems have been caused not by the technology itself, but by poor conception and implementation, cost overruns, and insufficient consumer education about usage of the technology and about what changes in electric service and bills to expect.

In Illinois, the ICC initiated a process in which all stakeholders in the Illinois electric industry could work together to collect information, exchange ideas and develop a framework to assist the Commission's consideration of smart grid investments and related policies. By collaborating on smart grid issues prior to regulatory proceedings about smart grid investments, Illinois stakeholders have improved the prospects for successful grid modernization decisions. Participants in the Illinois Statewide Smart Grid Collaborative have built a foundation of common knowledge and a mutual understanding of their different perspectives. Collaborative participants deserve thanks for all the time and energy they devoted to identifying and addressing the complex set of smart grid issues facing Illinois. The decisional framework laid out by them should well-serve Illinois in years to come.

[10] There are many sites with detailed smart grid information, including http://www.sgiclearinghouse.org/

[11] Utilities with installed meters include: AEP of Ohio - 200,000; AEP of Texas - 100,000; Alliant - 500,000; CenterPoint - 500,000; Delmarva - 200,000; ComEd - 120,000; FPL – 600,000; Idaho – 100,000; Oncor - 1,300,000; PG&E - 6,700,000; Portland General - 500,000; PPL - 1,300,000; SCE - 1,300,000; Southern - 1,000,000. All numbers are approximate

Executive Summary

Collaborative Overview

The Illinois Statewide Smart Grid Collaborative (ISSGC or Collaborative) was established by the Illinois Commerce Commission (ICC or Commission) in September 2008, by its Order in Docket No. 07-0566.[12] In taking this action, the Commission stated that the purpose of the Collaborative was: "*… to develop a strategic plan to guide deployment of smart grid in Illinois… and to recommend policies that the Commission can consider for adoption…"*[13] The Commission also directed that a third-party Facilitator[14] be engaged to direct the Collaborative and to submit a "Collaborative Report" by Oct 1, 2010.

The Collaborative is one step in the Commission's approach to smart grid decision-making – a process that relies on informed stakeholder participation by utilities, other stakeholders, and ICC Staff.[15] This Collaborative Report will be considered in a "Smart Grid Policy Docket," in which "the Commission may adopt the policy framework developed in the Statewide Smart Grid Collaborative in whole or in part, or modify the policy framework."[16] It is the Commission's stated goal that these activities ensure *"that consumers are the primary beneficiaries"* of smart grid deployment in Illinois.[17]

The work of the Collaborative occurred in two phases, beginning in early 2009. The focus of Phase One was to define the scope, objectives, approach, and timeline for the substantive work of the Collaborative to be accomplished in Phase Two. During the first half of that year, meetings and workshops were conducted by the Facilitator to engage stakeholders in setting specific objectives and tasks for the project. A stakeholder Steering Committee, led by the ICC Staff, assisted in this work and enumerated the following major tasks for the Collaborative to attempt:

1. Define "smart grid"
2. Understand the range of potential smart grid investments, including potential sources of cost and benefit
3. Identify smart grid policy issues, barriers, and recommendations
4. Define the technical characteristics and requirements for smart grid
5. Develop a cost-benefit framework for evaluating smart grid investment proposals
6. Define utility filing requirements for proposed smart grid investments
7. Prepare and deliver a final Report.

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[12] *Commonwealth Edison Company*, ICC Docket No. 07-0566, (Order, September 10, 2008); relevant sections are attached as Appendix X.

[13] Docket No. 07-0566, Order at 140

[14] EnerNex Corporation (http://www.enernex.com/) was selected as the facilitator.

[15] Docket No. 07-0566also authorized a separate series of stakeholder workshops to aid in developing a pilot approved by the Commission to test deployment of Advanced Metering Infrastructure (AMI) in the ComEd territory, a program that was approved by the Commission in Docket No. 09-0263 and began in late 2009.

[16] Docket No. 07-0566, Order at 142

[17] Docket No. 07-0566, Order at 140

The steering committee also requested that consideration of the thirteen "foundational polices"[18] the Commission directed the Collaborative to address be incorporated, where appropriate, into these seven tasks. The Report includes the following seven chapters: Smart Grid Definition, Smart Grid Applications, Consumer Policy Issues, Technical Characteristics and Requirements, Cost-Benefit Framework and Utility Filing Requirements. The following table shows where in this Report to find Collaborative's evaluation of these foundational policies:

Foundational Policy	Chapters					
	Smart Grid Definition	Smart Grid Applications	Consumer Policy Issues	Technical Characteristics and Requirements	Cost-Benefit Framework	Utility Filing Requirements
1) definition of a smart grid and its functionalities	✓	✓				
2) principles Illinois should use to guide smart grid planning and deployment, for example, interoperability, open architecture, and non-discriminatory access				✓		
3) uniform standards				✓		
4) methods of estimating, calculating and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs)					✓	
5) implications of smart grid technology for future policies regarding rate design, consumer protection, and customer choice			✓			
6) effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation			✓			
7) consumer education and dissemination of information about smart grid technologies, demand response programs and alternative rate structures			✓			
8) access by electricity market participants to smart grid functionalities			✓	✓		
9) data collection, storage, management, security, and availability to third parties			✓	✓		

[18] Docket No. 07-0566, Order at 141

Foundational Policy	Chapters					
	Smart Grid Definition	Smart Grid Applications	Consumer Policy Issues	Technical Characteristics and Requirements	Cost-Benefit Framework	Utility Filing Requirements
10) standards for interconnection of third party equipment				✓		
11) mechanisms to flow through to customers any utility smart grid revenues			✓			
12) adoption of new demand response programs			✓	✓		
13) open architecture and inter-operability standards for technological connectivity to the RTO or ISO to which a utility may belong				✓		

Phase One of the Collaborative was completed in July 2009. Phase Two focused on the Collaborative scope defined in Phase One, concluding with the submission of this Collaborative Report.

Participation in the Collaborative was open to all interested individuals and organizations. Active participants included ICC staff, utility companies, consumer advocates, government agencies, alternate retail electric suppliers, trade unions, environmental organizations, business associations, local government bodies, academics, vendor firms, Regional Transmission Organizations, and individual consumers with an interest in smart grid issues. A complete list of Collaborative participants is attached as Appendix B.

Although the Facilitator compiled this Report, its content was provided by Collaborative stakeholders. The Facilitator provided technical expertise where necessary, worked with the Collaborative to assess issues, and directed discussions in an effort to achieve consensus recommendations. The Report reflects consensus views and recommendations where consensus was achieved.[19] Where consensus was not achieved, the Report presents the differing perspectives. Collaborative participants agreed that views articulated in the Report would not be ascribed to individual stakeholders or stakeholder groups and that no attempt would be made in the Report to quantify or characterize the level of support for differing views.

[19] For the purposes of this Report, "consensus" is best defined by the Facilitator as agreement by stakeholders who developed a shared perspective on an issue, and the absence of an articulated contrary or alternate position.

This Report is not intended to be used to characterize the position of any party on an issue in a legal or regulatory proceeding.[20]

A description of the work process used by the Facilitator to engage participants is described in the chapter Collaborative Overview in the body of the Report.

Smart Grid Definition

Collaborative participants examined descriptions of the "smart grid" concept developed by the U.S. Department of Energy and set forth in federal law; but the Collaborative did not adopt its own definition of "smart grid." Both of these federal sources characterize the smart grid in terms of improved functional capabilities and the introduction or expansion of new and advanced energy technologies.

The U.S. Department of Energy's July 2009 "Smart Grid System Report[21] described smart grid deployment in the United States using as a framework these seven defining "characteristics of a modern grid" developed by the National Energy Technology Laboratory's Modern Grid Strategy project in 2008:

1. Enables Active Participation by Consumers in Demand Response
2. Accommodates All Generation and Storage Options
3. Enables New Products, Services, and Markets
4. Provides Power Quality for the Range of Needs in a Digital Economy
5. Optimizes Asset Utilization and Operating Efficiency
6. Addresses and Responds to System Disturbances in a Self-Healing Manner
7. Operates Resiliently Against Physical and Cyber Attacks and Natural Disasters.

Title XIII of the Energy Independence and Security Act of 2007 ("EISA07"), which established federal policy on the smart grid, begins with this statement:

> *It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:*
>
> *1. Increased use of digital information and controls technology to improve reliability,*

[20] As stated in the 07-0566 Order at 141, the purpose of the Collaborative is to "recommend policies to guide [smart grid] deployment that the Commission can consider for adoption in a docketed proceeding." Individual parties can present their positions and relevant evidence on the record in such a proceeding and in any subsequent utility-specific "Smart Grid Implementation Docket."

[21] http://www.oe.energy.gov/SGSRMain_090707_lowres.pdf

security, and efficiency of the electric grid.

2. *Dynamic optimization of grid operations and resources, with full cyber-security.*
3. *Deployment and integration of distributed resources and generation, including renewable resources.*
4. *Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.*
5. *Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.*
6. *Integration of "smart" appliances and consumer devices.*
7. *Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.*
8. *Provision to consumers of timely information and control options.*
9. *Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.*
10. *Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.*

The Collaborative accepted these descriptions of smart grid capabilities and technologies as a useful overview of smart grid. However, their inclusion in this Report is not intended to imply any particular regulatory policy or ratemaking treatment of future smart grid investments in Illinois.

Smart Grid Applications

There are numerous uses, or applications, of a smart grid. The Collaborative cataloged a broad range of smart grid applications as a resource for the Commission and as a framework for subsequent work. In total, twenty-eight smart grid applications were identified and grouped into seven categories.

- AMI Applications
  - Core AMI Functionality – the automated or on-demand capture of interval customer energy usage and other metering data through the use of "smart" meters connected to the utility through a two-way communications network
  - Remote Connect/Disconnect – utilization of a remotely operable integrated service switch to connect or disconnect a customer's electric service at the customer's request, for non-payment, or in response to a reported hazardous condition

- Outage Management Support -- utilization of the AMI system and data to support more efficient and effective identification and resolution of system outages
- Power Quality/Voltage Monitoring at the Meter -- extended utilization of the AMI system to capture power quality and voltage measurements at a customer's premises
- Customer Prepayment Utilizing AMI – utilization of the AMI system and an in-premises display to support customer pre-payment for electric service

➢ Customer-Oriented Applications

- In-Premises Devices for Energy Usage Data – utilization of the AMI system or other communications channels to provide customers with real-time information on their energy usage
- Customer Web Portal for Energy and Cost Data – utilization of an internet-based web portal to provide customers with historical information on their energy usage and related costs
- Outage Notification to Customer – notifying customers via a customer-designated communications channel (automated email, phone call, text message, etc.) of an outage at their premises and an estimated restoration time
- Government and Third Party Use of Customer Data -- the provision of customer meter data to customer-authorized third parties

➢ Demand Response

- Pricing Information to In-Premises Devices -- utilization of the AMI system (or other communications channels) and in-premises devices to provide customers with real-time information on their energy usage as well as energy price or event signals as a means to encourage energy conservation at high-demand/high-price periods or in response to critical grid operating conditions
- Direct Load Control – voluntary customer programs allowing the utility to remotely control customer demand through the installation of load control devices on customer equipment
- System Frequency Signal to Customer Load Control Devices – utilization of load control devices installed on customer appliances that automatically respond to changes in the electric system's frequency indicating an imbalance of generation and load
- System Renewables Output to Customers – providing customers with real-time information on the current mix of operating generation resources (specifically, the current output of renewable generation sources)

➢ Distribution Automation

- Automatic Circuit Reconfiguration – utilization of communicating switches and circuit reclosers to automatically reconfigure the distribution system during an outage, in order to limit the number of customers affected

- Improved Fault Location – utilization of fault-detecting sensors and communications networks to pinpoint the location of a system fault and expedite the restoration of service
- Dynamic System Protection for Two-Way Power Flows and Distributed Resources – utilization of systems and devices to automatically detect and control output from distributed resources in order to maintain safety and stability
- Dynamic Volt-VAR Management – utilization of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to control the voltage and reactive power on the system
- Conservation Voltage Optimization – utilization of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to reduce voltage levels and customer energy usage

➢ Asset/System Optimization

- Enhanced System Modeling and Planning – utilization of AMI and other system operating data to improve system modeling capabilities and long-term system planning effectiveness
- Asset Sizing Optimization – utilization of AMI data to provide more optimal sizing of distribution equipment
- Asset Condition Monitoring – real-time monitoring of assets' operating parameters to detect (and respond to) impending asset failure or to initiate predictive asset maintenance

➢ Distributed Resources

- Customer Distributed Resource Interconnection – facilitated grid interconnection of customer-owned generation and storage
- Coordinated Management of Distributed Resources – utility coordination of customer-owned generation and storage
- Electric Vehicles: Optimized Charging – management of electric vehicle charging to optimize vehicle availability and local distribution network loading, and to minimize customer charging costs
- Dispatch of Electric Vehicle Storage (Vehicle to Grid, or "V2G") – managing the dispatch of energy from customer electric vehicles to the grid

➢ Transmission

- Wide Area (Phasor) Measurement – utilization of phasor measurement units and high-speed communications networks to predict and prevent conditions that could lead to grid instability
- Wide Scale Outage Recovery – utilization of grid sensing devices and discrete control devices to measure existing grid conditions and improve speed of restoration following a wide-scale outage

– Enhanced Physical Security – utilization of devices, sensors, and communications networks to enhance the physical security of distribution and transmission facilities

The Collaborative identified the potential costs, potential benefits and beneficiaries, and potential negative impacts associated with each application. The following table identifies the primary categories of beneficiaries and characterizes the types of potential benefits that might be achieved through the use of smart grid functionalities:

Beneficiary	Potential Benefits
Customers	• Reductions in customer costs for electric delivery service and energy supply service • Decreases in power outages • Improved power quality
Distribution and Transmission Utilities	• Reduction in operating costs • Improved system reliability • Increased levels of customer satisfaction • Optimized assets • Mitigation of risks
Regional Electricity Markets	• Reduction in regional energy and/or capacity prices
Competitive Suppliers, Third Parties, and Government	• Enabling the creation of new value-adding products/services for customers or constituents
RTOs/ISOs	• Increased grid stability • Improved system awareness • Improved forecasting • More competition in markets for ancillary services
Society	• Environmental benefits • Improvements to public health and safety • Economic development • Improvements to or the expansion of broadband communications networks

Some of the potential negative impacts identified by the Collaborative are shown in the following table.

Category	Potential Negative Impacts

Customers	• Increases in customer utility bills • Increases in disconnections for non-payment • Privacy loss • Customer confusion related to increased bills, new pricing structures and utility and third party solicitations
Utility Operations	• Increased employee exposure to back feed from increased customer generation and storage • Potential increases in undetected energy theft due to decreased service visits
Societal	• Higher number of customers without electric service due to disconnection for non-payment as a result of higher utility bills, remote disconnections and potential prepayment policies

The Collaborative did not conduct a cost-benefit analysis of each application and, does not offer an opinion on their projected value. All identified benefits and negative impacts should be understood as potential benefits or potential negative impacts, which may or may not occur depending on a variety of regulatory, behavioral, technical and market factors. Although the Collaborative mapped potential benefits to specific customer groups, ultimately benefits may be realized to varying degrees by individual customers or within customer groups.

Consumer Policy Issues

Protection of consumers has always been a central focus of public utility regulation. That need will not be diminished -- and, in fact, the task will become more complex -- as new utility functions and consumer choices are introduced through smart grid deployment. Six of the thirteen foundational policies enumerated in the Order to be addressed by the Collaborative are directly related to consumer interests:

- implications of smart grid technology for future policies regarding rate design, consumer protection, and customer choice;
- effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation;
- consumer education and dissemination of information about smart grid technologies, demand response programs and alternative rate structures;
- access by electricity market participants to smart grid functionalities;
- mechanisms to flow through to customers any utility smart grid revenues; and,
- adoption of new demand response programs.

Many state regulatory policies may need to be reexamined, and some new policies may have to be enacted, to ensure adequate consumer protection during and after smart grid deployment. This Report examines eight areas of consumer interest policy that may be affected by deployment of the smart grid applications identified in Chapter [XX] and that encompass the issues in the foundational policy concerns listed above:

- Data Privacy and Data Access
- Competitive Retail Market Structure
- Remote Connection and Disconnection
- Customer Prepayment for Service
- Utility Rates in a Smart Grid Environment
- Smart Grid Consumer Education
- Recovery of Utility Smart Grid Costs
- Statutory Energy Goals and Smart Grid

A brief description of the issues and recommendations in each of these topic areas is presented below. However, the reader should refer to the full chapter for a more complete understanding of the work of the Collaborative on consumer policy issues.

Data Privacy and Data Access

Smart grid applications will capture and transmit information about utility system conditions as well as private information about individual customer consumption and consumer behavior. That customer information must be protected from unauthorized collection, release, sharing, use or retention. The Collaborative makes thirteen policy recommendations in this area:

1. AMI systems should be designed so that customers can securely retrieve usage data directly and in near real time from the meter securely through in-premises devices.

2. Customers should have access to collected historical usage and billing data for a reasonable period of time, via a utility-provided web portal.

3. Customer authorization should continue to be required for access to any customer-specific meter data by a third party, and its use should be disclosed by the third party to the customer.

4. Third parties should fully disclose in plain language the scope, duration, and purpose(s) of the requested access to customer-specific meter data. In addition, customer complaints regarding access to or use of data should be subject to the Commission complaint process.

5. The utility should provide electronic access to billing and usage data to customer-authorized third parties within a reasonable period of time from receipt of authorization; any fees to provide this service should be outlined in the tariff and reflected in regulated revenue.

6. A service and supply agreement with a customer should explicitly authorize an Alternate Retail Electric Supplier (ARES) to access and use usage and billing data for billing purposes. Any authorization to access historical data or other information not directly related to billing and collection should be explicitly stated in such an agreement. Authorization to provide usage information to an ISO should be included, if necessary. Cancellation or expiration of the supply agreement should also revoke a supplier's access rights to the customer's data. A utility should not be required to customize or disaggregate data.

7. Utilities and customer-authorized third parties should be responsible for protecting all meter data in their possession from unauthorized release.

8. The utility should be allowed to use customer-specific meter data to support operation of utility systems and the electricity transmission and distribution network, or as required by State and federal authorities.

9. The utility should be allowed to use customer-specific meter data to solicit participation in Commission-approved demand response and energy efficiency programs.

10. Stakeholders agree that the utility should only be allowed to make use of the Meter Data and Customer Data for offering a competitive service or share such information with any affiliated or unaffiliated entity to the extent allowed by, and consistent with all applicable laws, ICC rules and orders. Some stakeholders further believe that if a utility or its affiliate offers competitive services, they should not, under any circumstances, be allowed to use

customer Meter Data in offering those services without affirmative customer authorization and application of third party disclosure requirements.

11. Governmental units should not have unauthorized access to customer-specific data except insofar as some customer-specific data (such as regarding outages, disconnections, and other information potentially affecting public health and safety) is already shared with government by the utility under existing law, policies and agreements. [See e.g., 220 ILCS 5/8-202(b)] The utility should adopt policies and procedures that comply with state and federal law to respond appropriately to law enforcement requests for AMI-derived data.

12. Customers should be educated and informed about what it means to allow access to AMI-derived data.

13. If a utility provides a third party with aggregated AMI meter data, it must take reasonable measures to protect the identity of individual customers. Where individual customer data privacy cannot reasonably be assured, the third party should obtain authorization from the customer for access to identifiable customer data prior to its release by the utility.

Competitive Retail Market Structure

Illinois law provides for the possibility of retail competition in electricity supply (i.e., power and energy) services for residential, commercial and industrial customers (see: 220 ILCS 5/16 of the Public Utilities Act). ComEd and the Ameren Illinois Utilities have each elected to operate as an Independent Distribution Company (IDC), subject to rules that provide they "shall not promote, advertise or market with regard to the offering or provision of any retail electric supply service." 83 Ill. Admin. Code 452.240(a). However, these rules do not preclude "advertising or marketing permissible IDC services other than retail electric supply services." 83 Ill. Admin. Code 452.240(b). Utilities today operate mandated energy efficiency and demand response programs that might be enhanced by the provision of "post-meter devices" (PMD) enabled by smart grid technology. Thus, both utility and non-utility providers of smart grid-enabled services potentially could operate to the benefit of consumers in Illinois. However, Individual customers may or may not experience specific or identifiable benefits from enhanced energy supply products and services facilitated by smart grid deployment, regardless of supplier. This disparity in potential benefits may result in some customers paying higher bills for the costs of smart grid investments without experiencing any identifiable benefits in the form of lower individual bills or lower electricity prices overall.

The Collaborative makes six policy recommendations in this area:

1. AMI systems deployed by utilities in Illinois should allow consumers to easily connect in-home devices and networks, providing a full range of opportunities for customers to employ tools to optimize cost effective demand response and achieve energy management objectives. Collaborative participants have not reached consensus as to whether any costs of PMD should be considered for recovery through utility rates. Any proposal to subsidize or fund the purchase of PMD for customers should, at a minimum, reflect a cost benefit analysis that includes the costs associated with installing and maintaining such devices, the

projected demand response or usage reduction benefits that will occur over the estimated life of the device, and the cost of educating customers about the use of the device.

2. To the extent that PMDs are found by the Commission to be necessary to capture AMI customer benefits, and that a demonstrable business case is made for utility involvement in their provision to consumers, policies to facilitate access to PMDs may be warranted. In assessing how utilities could aid customers in obtaining PMDs without impeding PMD market development, the Commission should compare the projected effects of direct utility provision of PMDs with the projected effects of using non-utility distribution channels.

3. Any provision of PMD by a utility is subject to IDC rules and should not require the customer to purchase utility supply in order to receive and make use of the PMD. To the extent practicable, PMD should be capable of presenting billing and pricing information from either a utility or an ARES.

4. Any PMD subsidies that may be deemed by the Commission to be appropriate in order to achieve smart grid objectives should be competitively neutral with respect to electricity supplier.

5. Smart grid policies should be consistent with but not dependent upon the state's policy to foster the development of retail electric competition. In the evaluation of proposed utility rate offerings and demand response programs, the Commission should be guided by actual experience concerning the interplay between such programs and the development of retail competition. In determining smart grid policy, the Commission should consider the effect of such policies on the development of retail competition and the effect of retail competition on achievement of the goals of smart grid deployment.

6. In order to protect consumers and allow the nascent market in smart grid-enabled products and services to develop, the Commission and other consumer protection authorities should closely monitor consumer complaints in order to quickly address problems and issues that may need formal regulatory attention. Where preventive regulation is needed, appropriate consumer protections should be ordered or enacted.

Remote Connection and Disconnection

AMI systems may include meters with an integrated "service switch" that can be opened or closed remotely by a signal from the utility, allowing the utility to connect or disconnect service upon the request of a customer, to disconnect service for non-payment, and to reconnect service after payment is received. Whether Illinois utilities should be allowed to remotely disconnect service for non-payment, and if so, what rules should be in place, was a matter of some disagreement among participants in the Collaborative, and no recommendation is made in this Report. A detailed discussion of this issue is found in the Consumer Policy Issues Chapter of this Report.

Customer Prepayment for Electricity Service

Prepayment of electricity service would provide a customer with the option to purchase a specified amount of electricity at a specified price in advance of its use. Prepayment could serve as an alternative to deposit requirements for utility service, and may reduce the utility's credit and collection costs; however, costs of operating a prepayment program might be high compared to savings realized by the utility. Moreover, prepayment for electricity raises significant social and policy issues regarding equitable access to an essential utility service. Since no AMI-enabled prepayment program has yet been successfully demonstrated, the following seven recommendations urge a cautious and comprehensive evaluation by the ICC of any prepayment program proposal, including:

1. development of an Illinois-specific cost-benefit analysis showing net system and individual benefits from customer prepayment without adverse implications for customer health and welfare compared to the current system;

2. study of policies and procedures that could affect the rights of customers on a voluntary prepayment program to remain protected by seasonal disconnection moratoria (PUA Sec 8-205, 8-206) medical disconnection prohibitions, and any other disconnection rules intended to protect consumer health and public safety;

3. consideration of the feasibility of customer options other than automatic disconnection if the account balance runs to zero;

4. implementation of rules to require and technological capabilities to enable immediate application of customer payments and the customer's prompt access to utility service;

5. an analysis of how fixed distribution costs would be recovered under the specific proposed program;

6. guidelines regarding marketing of prepayment programs, to ensure that customers are made aware of all mechanisms to retain utility service, including subsidies, payment plans, government-funded and utility-sponsored energy assistance programs, and other available options; and,

7. prohibition of the utility disconnecting service to a customer based upon request of a third party.

Utility Rates in a Smart Grid Environment

Advanced metering systems can allow a utility either to replace "flat" rates with "time-variant" rates, or to offer customers a choice of rate structures. Flat rates, in use today for the vast majority of residential and small commercial customers in Illinois, generally remain constant throughout the day and year. Variable rates change, either according to a pre-determined plan (e.g., time-of-use (TOU) rates) or in response to the wholesale price of electricity (e.g., "real-time price" (RTP) rates).

The ability to offer customers a choice of rate plans raises the policy question of what is the appropriate initial “default” utility rate for residential and small commercial customers. There are many different views in the Collaborative on this issue and no recommendation is made in this Report. A detailed discussion of this issue is found in the Consumer Policy Issues chapter of this Report.

Smart Grid Consumer Education

An important aspect of the smart grid is its ability to enable active participation by customers in energy management and consumers will need to be actively supported in acquiring the knowledge and skills to do so. Thus, the goal of consumer education for Commission-approved utility smart grid programs should be to provide customers with ample information to make informed choices about their participation. Consistent with this goal, consumer education and outreach efforts should be developed to support implementation of any smart grid programs and smart grid-enabled rate structures. Program-specific consumer education should be designed to achieve the following objectives:

1. Consumers should understand the nature of the program, including:
   a. a basic understanding of the technologies being used or new options available to the consumer;
   b. an understanding of any associated rate structure changes or options;
   c. the role of the utility and third parties.
2. Consumers should understand the goals of the program, including potential individual and societal costs and benefits.
3. Consumers should have a clear understanding of the potential implications (benefits, costs, and risks) associated with their participation (or non-participation) in a smart grid program or rate option in light of their personal electricity needs and usage profile. Potential costs and benefits could include bill impacts and service changes, as well as identified environmental and societal impacts that have been documented. Risk implications could include price volatility, potentially higher bills, and data privacy/access issues.
4. Although Collaborative participants do not agree about how to communicate this information, all agree that consumers should be informed of any changes in utility disconnection/reconnection practices associated with deployment of AMI.
5. Consumers should be informed of the resources and tools available to them that could be employed to estimate the potential effect of their participation in a smart grid-enabled program, to maximize the value they derive from it, and/or to minimize any potential negative impacts. These resources and tools may include rate comparison tools, energy consumption comparisons, in-home devices, and smart appliances.

6. Consumer education program messaging should be competitively neutral with respect to the customer's choice of an electricity supplier.

7. Consumer education should be an element of cost-benefit analysis in any proceeding regarding approval of a smart grid deployment request.

Recovery of Utility Smart Grid Costs

The issue of smart grid cost recovery has been a matter of controversy and litigation in Illinois for several years. In brief, 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. This controversy was clearly noted by the Commission in the 2007-0566 Order when it approved a rider for the limited purpose of recovering the costs of ComEd's AMI pilot program, and stated that it would again consider a proposal for rider recovery of smart grid costs after completion of its Policy Docket and during any subsequent Smart Grid Implementation Docket.

Some stakeholders are concerned that utility proposals for extraordinary 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. Some other stakeholders believe that non-traditional cost recovery would be essential to accelerated deployment of smart grid technologies. There was no consensus on this matter among participants in the Collaborative; no recommendation is made in this Report. A detailed discussion of this complex issue is found in the Consumer Policy Issues chapter of this Report.

Statutory Energy Goals and Smart Grid

Illinois is one of 29 states with a legislated goal of procuring increasing amounts of renewable electricity output, such as wind power and solar power, to displace fossil-fueled generation (known as the Renewable Portfolio Standard (RPS), and one of 23 states with a statutory requirement for Energy Efficiency (EE) investment. Illinois is also one of only several states that have enacted specific demand response (DR) standards for utilities.

The statutory RPS, EE and DR standards were set prior to consideration of smart grid deployment and compliance with them must occur whether or not smart grid deployments occur in Illinois. From this perspective, Illinois' statutory energy goals may not affect smart grid planning and implementation. However, meeting certain of these energy goals within the cost caps may eventually be facilitated by, if not dependent on, smart grid functionalities.

For example, smart grid applications could ease the integration of small-scale solar and other household or locally-based distributed renewable generation. Smart grid investments directed to providing more granular usage and pricing information to customers may contribute to overall improvement in energy efficiency. Similarly, smart metering could create the opportunity for pricing programs designed to reduce peak demand. While not supplanting statutorily mandated utility programs, deployment of smart grid technology could contribute towards meeting or even exceeding existing statutory objectives.

In short, the interplay between smart grid development and achievement of Illinois' statutory energy goals suggests that there may be some "effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation." The degree and timing of any such effect is not known at this time and is a question for consideration by the Commission and the General Assembly as the pace and scope of smart grid technology development and deployment evolves.

Technical Characteristics and Requirements

Background

The Commission's concern about technical matters related to smart grid is reflected in its order authorizing the Collaborative. At least six of the "foundational policies" identified in the order as part of the scope of the Collaborative relate to technical considerations. The technical issues identified in these foundational policies include: interoperability, open architecture, non-discriminatory access; uniform standards; access by electricity market participants to smart grid functionalities; data collection, storage, management, security, and availability to third parties; standards for interconnection of third party equipment; and open architecture and inter-operability standards for technological connectivity to the RTO or ISO.

There are a variety of proprietary, industry, national, and international standards that are applicable to smart grid applications. Since the formation of the Collaborative, the National Institute of Standards and Technology (NIST) was charged by Congress with "responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems." NIST has since issued the first version of its Smart Grid Interoperability Framework and is working with stakeholders and standards bodies to accelerate the standards development process.

With this activity at the national level and with the emphasis placed by the Commission on the technical aspects of smart grid at the state level, the Collaborative developed a set of recommended smart grid technical requirements and guidelines for the Commission's consideration.

Summary of Recommendations

The Collaborative recommends the use of open technologies over proprietary ones, and recommends the use of officially recognized and standardized technologies over those that are not. However, the requirements and recommendations described in this Report do not specify the use of any particular technology, standard or best practice, for the following reasons:

1. The scope of the smart grid exceeds local or state boundaries. To identify standards that only apply within Illinois would potentially create barriers to interoperability between utilities in different states. Specifying an Illinois-only standards framework

could possibly limit the products and services available to consumers within Illinois.

2. The U.S. Federal government has begun the process of establishing nationwide smart grid standards by directing the NIST to develop an interoperability framework. The first version of this national framework has been published. Therefore, any attempt to require Illinois utilities to use particular technologies could conflict with the national efforts and could work against achieving interoperability.

While the Collaborative does not propose strict adherence to national smart grid standards, it recommends that Illinois utilities be required to explain their choice of any standards or technologies that are not recommended by the NIST Smart Grid Interoperability Framework.

Recommendations on the Technical Characteristics and Requirements of smart grid fall into two categories: Design Issue Requirements and Application-Specific Requirements. Application-Specific Requirements are unique to a specific application type and would be in addition to the general Design Issue Requirements. Application-Specific Requirements (and related recommendations or guidelines) are documented in the body of the Report for each smart grid application.

Design Issue Requirements apply to all proposed smart grid investments and are related to a set of critical smart grid design issues identified by the Collaborative. The Collaborative recommends that the utility provide a thorough discussion of each of the following design issues as they relate to its proposed smart grid investment:

- Capacity -- the ability of a communications link to carry data; includes the impact of factors such as latency, data volume, and event rate
- Technical maturity and risk -- the level of certainty that the technology will meet the requirements of the application
- Openness and standardization – Open technologies lack barriers to implementation or integration, and have few or no royalties or license fees. Standardization is the degree to which the technologies used to implement the application are recognized by official organizations and the user community
- Security – the degree to which the data, equipment, persons and organizations involved in the application must be protected from attack, whether physical or electronic
- Manageability -- the degree to which devices, systems, and data must be configured, synchronized, tracked, diagnosed and/or maintained in order to implement the application. It includes the ability to measure the health and the performance of the system.
- Upgradeability -- the degree to which the devices and systems that implement the application can be changed to adapt to future conditions
- Scalability -- the degree to which the application's system(s) will permit future expansion

- Reliability – the degree to which systems associated with the application can automatically recover from power, communications and component failures, in order to minimize the impact on the customer and the systems
- Interactivity with Customers -- the degree to which the system implementing the application helps the power system and its users react to each other's needs.

Cost-Benefit Framework

Background

Modernizing the electricity system in Illinois to achieve the characteristics of a smart grid requires both initial and ongoing investment and expenditures that must meet with regulatory approval. Hence, one of the thirteen foundational policy issues the Commission directed the Collaborative to consider was:

> *"methods of estimating, calculating and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs)"*[22] [of smart grid projects or investments].

The Collaborative adopted the following objective to address this issue: Develop a standardized cost-benefit framework for proposed smart grid investments so that future debates about the cost-effectiveness of potential smart grid investments in Illinois can center on the reasonableness and supportability of estimated costs and benefits rather than the methodology for conducting cost-benefit analysis.

Because cost-benefit analysis of smart grid investments is a relatively new practice in most state jurisdictions, there was no comprehensive "off-the-shelf" methodology specific to evaluating smart grid investments available to guide the Collaborative's work. The evaluation of smart grid investments is complicated by a number of issues, including:

- Uncertainties surrounding the realization of certain benefits, particularly those that are dependent on changes in end-user behavior
- The presence of multiple beneficiary groups (e.g.. ratepayer, utility, resource, society)
- Challenges in quantifying (determining how much of an impact) and monetizing (determining the economic value of the quantified impact) certain incremental benefits associated with smart grid investments, especially reliability and environmental benefits.

The cost-benefit methodology for smart grid investments proposed by the Collaborative attempts to address each of these challenges within a consistent, standardized framework.

[22] Docket No. 07-0566, Order at 141.

Basics of the Framework

Smart grid applications can be expected to require upfront capital investment and ongoing operational expenses. Benefits may occur gradually and over extended periods of time. Therefore, cost-benefit analyses in support of smart grid investments should convert future expected streams of costs and benefits into a present value amount using an appropriate discount rate. Any and all costs and benefits associated with a proposed smart grid investment should be included in the analysis, provided they are,

a) significant (expected to have a meaningful economic impact on the investment decision),

b) quantifiable and transparent (reasonably and openly quantified and monetized), and

c) relevant (to the analysis or the Commission's approval decision).

Examples of potential benefits, costs, and potential negative impacts are described in the Smart Grid Applications chapter of this Report.

Recommendations

The Collaborative's recommendations for a cost-benefit framework to analyze smart grid investments are described in detail in the body of this Report. Eight important recommendations are highlighted here:

- Various perspectives, or tests, have been utilized historically to evaluate demand-side management (DSM) programs and can be modified for application to smart grid investments. The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analyses, including the following:
    - Total Resource Cost (TRC) – both with societal costs and benefits and without societal costs and benefits
    - Ratepayer Impact Measurement (RIM) -- depicting how customers' rates would be affected
    - Participant Cost Test (PCT) -- depicting the impact of customer-specific costs and benefits
- As appropriate to each test, the cost-benefit analysis should separately identify:
    - those costs and benefits that will be directly incurred or realized by ratepayers through the traditional ratemaking structure
    - those costs that can be expected to be incurred by non-utility parties
    - those benefits that will flow, if at all, through the wholesale price of energy or other markets

    - those benefits associated with broader societal objectives or results that are not necessarily reflected in regulated customer rates.

- The utility should be required to include a sensitivity analysis as part of a cost-benefit analysis. Good candidates for inclusion in the sensitivity analysis are variables (such as emission costs and reliability) that have a wide range of potential values.
- A cost-benefit assessment of smart grid investments and approaches should include identification and discussion of other investments or approaches (if any) that reasonably might achieve similar or better results.
- To the extent that they can be reasonably quantified (and attributed to the smart grid investment), environmental benefits and reliability should be monetized in appropriate tests. Any assumptions regarding environmental benefits (e.g., emissions reduced, values of emissions/allowances) should be clearly stated and supported.
- The estimation of potential benefits associated with changes in load shape should be accompanied by a discussion of the methodology and assumptions used in deriving the estimates. Benefits projected for outside of Illinois can be noted, but should not be included in a cost-benefit analysis except in support of a societal test.
- After deployment, the Commission should periodically evaluate if the projected costs and benefits associated with an approved smart grid investment are being realized for customers, the utility, society, and/or other stakeholders prior to approving similar future investments.
- The Commission's decision to approve (or not) any particular smart grid investment may be based on a number of considerations, some of which (e.g., policy considerations) could be outside the context of the cost-benefit analysis. A cost-benefit analysis or any particular cost-benefit test or tests should be viewed as an important tool to inform decision making, but not as a determinative standard.

Collaborative participants expressed differing views on how the Commission should evaluate the results of smart grid cost-benefit analyses. These views are articulated in the Cost-Benefit Framework chapter of this Report.

Utility Filing Requirements

Utilities seeking cost recovery in the State of Illinois must provide supporting information to the Commission. For traditional (general rate case) filings, supporting information requirements are well established. However, a formal set of filing requirements for non-traditional smart grid cost recovery (that is, any type other than a general rate case) have not been defined.

Collaborative stakeholders were able to achieve some agreement on the general nature and content of filing requirements. However, there was fundamental disagreement among stakeholders about how "filing requirements" should be understood. One group of stakeholders holds that filing requirements should be mandatory unless a waiver is granted. A second group of stakeholders is concerned that a filing might be stricken or dismissed should one or more of the filing requirements not be met. This second group of stakeholders believes that filing requirements should be understood more as guidelines rather than legal requirements.

Given these differing views on the interpretation of "filing requirements," the Collaborative developed recommendations for supporting information that should be provided by an Illinois utility seeking non-traditional cost recovery for smart grid investments. These recommended filing requirements fall into three categories:

- Cost-Benefit Requirements – extracted from and informed by requirements identified in the Cost-Benefit Framework chapter
- Technical Requirements -- extracted from and informed by requirements identified in the Technical Characteristics and Requirements chapter
- Cost Recovery Requirements -- a set of financial and other information, including:
    - Forecasts of capital investments and other expenses
    - Description of and support for the proposed cost recovery mechanism
    - Anticipated rates and bill impacts by customer class
    - Description of proposed new tariffs or changes to existing tariffs
    - Analysis supporting the proposed rate of return

The Collaborative discussed whether it would be appropriate to modify the existing filing requirements identified in 83 Illinois Administrative Code 285 ("Part 285"), which are the mandatory information requirements for public utilities in a rate case. Collaborative stakeholders expressed differing views on whether existing Part 285 requirements should apply to non-traditional cost recovery requests. Some stakeholders believe that those requirements should apply in whole unless a waiver is granted. Other stakeholders maintain that specific Part 285 requirements should be excluded. A third group of stakeholders believes that Part 285 requirements would be excessive and burdensome in this context and may also be legally incompatible with certain alternative cost recovery mechanisms. This third group believes that these requirements should not apply to filings for non-traditional cost recovery of smart grid investments.

Collaborative Overview

Origin and Purpose of the Collaborative

The Illinois Statewide Smart Grid Collaborative (ISSGC or Collaborative) was established by the Illinois Commerce Commission (ICC or Commission) on September 10, 2008, by its Order in Docket No. 07-0566 (Order).[23] [24] The Collaborative is one step in an orderly approach to smart grid decision-making – a process that relies on informed participation by utilities, other stakeholders, and ICC Staff. In addition to the Collaborative, the Order also authorized a separate series of stakeholder workshops to aid in developing a pilot to test deployment of Advanced Metering Infrastructure (AMI) in Commonwealth Edison's (ComEd) service territory, a program that was approved by the Commission in Docket No. 09-0263 and began in late 2009. The content and recommendations of this Collaborative Report of the ISSGC will be considered by the Commission in a "Smart Grid Policy Docket," in which "the Commission may adopt the policy framework developed in the Statewide Smart Grid Collaborative in whole or in part, or modify said policy framework."[25] It is the Commission's stated goal that these activities ensure "that consumers are the primary beneficiaries" of smart grid deployment in Illinois.[26]

The Collaborative examined smart grid functionalities that fall within a broad continuum of stakeholder interest and plausible cost-benefit balance. No determination was made that any particular investments should or should not be undertaken, or that the identified potential benefits (or negative impacts) of smart grid functionalities are certain to be realized. Instead, this Report is designed to provide a comprehensive decisional framework for both general policymaking and utility-specific investment evaluations. It is intended to serve as a guide for the Commission, the General Assembly, Illinois utilities and their customers as they evaluate investments to add smart grid functionalities to the state's electric systems and consider related policies intended to optimize grid modernization strategy and maximize its net benefits. Although the Collaborative examined, and this Report documents, all expressed viewpoints of participating stakeholders, specific outcomes of future Commission proceedings addressing smart grid issues and proposals are not presumed. Rather, this Report presents facts and perspectives to inform those decisions.

[23] *Commonwealth Edison Company*, ICC Docket No. 07-0566, (Order, September 10, 2008); relevant sections are attached as Appendix X.

[24] The Commission's order in the Ameren Illinois Utilities 2007 general rate cases also directed Ameren to participate in the Statewide Smart Grid Collaborative established by the 07-0566 Order. (ICC Docket Nos. 07-0585, 07-0585, 07-0587, 07-0588, 07-0589 and 07-0590 (Consolidated), Order at 264-265)

[25] Docket 07-0566, Order at 142

[26] Docket 07-0566, Order at 140

Organization of the Collaborative

The ICC Order called for the Executive Director of the Commission to select a third-party Facilitator for the ISSGC to be engaged by the two largest investor-owned utilities in Illinois, ComEd and the Ameren Illinois Utilities (AIU). EnerNex Corporation was selected as the Collaborative Facilitator and began work in December 2008.

The work of the Collaborative occurred in two phases, beginning in early 2009. The focus of Phase One was to define the scope, objectives, approach, and timeline for the substantive work of the Collaborative to be accomplished in Phase Two. During the first half of that year, meetings and workshops were conducted by the Facilitator to engage stakeholders in setting specific objectives and tasks for the project. A stakeholder Steering Committee, led by the ICC Staff, assisted in this work and enumerated the following major tasks for the Collaborative:

1. Define "smart grid"
2. Understand the range of potential smart grid investments, including potential sources of cost and benefit
3. Identify smart grid policy issues, barriers, and recommendations
4. Define the technical characteristics and requirements for smart grid
5. Develop a cost-benefit framework for evaluating smart grid investment proposals
6. Define utility filing requirements for proposed smart grid investments
7. Prepare and deliver a final Report.

The Steering Committee also requested that consideration of the thirteen (13) "foundational policies"[27] which the Commission directed the Collaborative to address be incorporated where appropriate into these seven tasks. The Report includes the following seven chapters: Smart Grid Definition, Smart Grid Applications, Consumer Policy Issues, Technical Characteristics and Requirements, Cost-Benefit Framework and Utility Filing Requirements. The following table shows where in this Report to find the Collaborative's evaluation of these foundational policies:

Foundational Policy	Chapters					
	Smart Grid Definition	Smart Grid Applications	Consumer Policy Issues	Technical Characteristics and Requirements	Cost-Benefit Framework	Utility Filing Requirements
14) definition of a smart grid and its functionalities	✓	✓				
15) principles Illinois should use to guide smart grid planning and deployment, for example,				✓		

[27] Docket 07-0566, Order at 141

Foundational Policy	Chapters: Smart Grid Definition	Smart Grid Applications	Consumer Policy Issues	Technical Characteristics and Requirements	Cost-Benefit Framework	Utility Filing Requirements
interoperability, open architecture, and non-discriminatory access						
16) uniform standards				✓		
17) methods of estimating, calculating and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs)					✓	
18) implications of smart grid technology for future policies regarding rate design, consumer protection, and customer choice			✓			
19) effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation			✓			
20) consumer education and dissemination of information about smart grid technologies, demand response programs and alternative rate structures			✓			
21) access by electricity market participants to smart grid functionalities			✓	✓		
22) data collection, storage, management, security, and availability to third parties			✓	✓		
23) standards for interconnection of third party equipment				✓		
24) mechanisms to flow through to customers any utility smart grid revenues			✓			
25) adoption of new demand response programs			✓	✓		
26) open architecture and inter-operability standards for technological connectivity to the RTO or ISO to which a utility may belong				✓		

Additionally, while not included in the Order as foundational policies to be considered, the Collaborative also addressed Cost Recovery and Cost Allocation. These discussions are included in the Consumer Policy Issues chapter of the Report.

Phase One of the Collaborative was completed in July 2009. Phase Two focused on the Collaborative scope defined in Phase One, concluding with the submission of this Collaborative Report at the end of September 2010.

Overview of the Collaborative Process

Participation in the Collaborative was open to any and all individuals and groups. While some of the 290 stakeholders who joined the Collaborative did not participate regularly or in all its activities, many others worked assiduously for months. Active participants included ICC Staff, electric utility companies, consumer advocates, government agencies, alternate retail electric suppliers, trade unions, environmental organizations, business associations, local government bodies, academics, vendor firms, Regional Transmission Organizations, and individual consumers with an interest in smart grid issues. A complete list of Collaborative participants is attached as Appendix B.

In the Collaborative process, the Facilitator worked to ensure that all views were given equal weight and full expression, regardless of the stakeholder from which they originated, provided that they did not promote the private interests of any particular vendor group. At the outset, participants agreed that views could be circulated without attribution so as to encourage uninhibited expression about smart grid issues. No "votes" were taken to assess the popularity of a particular idea; instead, all perspectives were subject to probing discussion by the group to assure that views articulated in the Report were fully vetted.

The Facilitator was responsible for preparing and assembling this Collaborative Report. However, the content of the Report was provided by Collaborative stakeholders. The role of the Facilitator was to assist the Collaborative in completing the goals of the Order as outlined by the Steering Committee in Phase One. The Facilitator provided technical expertise where necessary, worked with the Collaborative to assess myriad issues associated with consideration of smart grid technology investment and deployment and sought to achieve consensus recommendations. The Report reflects consensus views and recommendations where consensus was achieved. Where consensus was not achieved, the Report presents the differing perspectives. Stakeholders agreed that views articulated in the Report would not be ascribed to individual stakeholders or stakeholder groups and that no attempt would be made in the Report to quantify or characterize the level of support for differing views.

Much of this Report reflects consensus views and recommendations. In the context of the Collaborative, "consensus" is best defined as agreement by stakeholders who developed a shared perspective on an issue addressed by the Collaborative and the absence of an articulated contrary or alternative position after review by the full Collaborative. Although this

Report was developed with the active participation of a broad group of stakeholders and all content was circulated to the entire Collaborative for comments and editorial suggestions, the participation of some stakeholders was limited by time, resource constraints, and/or competing priorities. "Consensus" views expressed in the Report should not be interpreted as representing the full agreement of every stakeholder participating in the Collaborative, because some stakeholder organizations did not participate in developing all sections of the Report.

For that reason, and because the Collaborative was not conceived as an evidentiary process (as would be appropriate to a docketed proceeding), this Report is not intended by stakeholders to be used to characterize the position of any party on an issue in a legal or regulatory proceeding or to serve as a substitute for proof of any fact in such a docketed proceeding. As stated in the Order, the purpose of the Collaborative is to "recommend policies to guide [smart grid] deployment that the Commission can consider for adoption in a docketed proceeding." Docket 07-0566, Order at 141. Individual parties can present their positions and relevant evidence on the record in such a proceeding and in any subsequent utility-specific "Smart Grid Implementation Docket."[28]

Operation of the Collaborative

To expedite the work of the full Collaborative, small workgroups of Collaborative volunteers were formed to draft the initial efforts in each targeted area of the Collaborative's focus as determined in Phase One.

- Smart Grid Applications and Technologies
- Consumer Policy Issues
- Technical Characteristics and Requirements
- Cost-Benefit Framework
- Utility Smart Grid Filing Requirements

The major task of each workgroup was to develop "strawman" content for their area of focus to present to the full Collaborative. This content typically included detailed scoping of the area, definition of issues, and creation of policy recommendations. Facilitators assisted the workgroups in drafting language, exchanging and testing assertions and attempting to achieve consensus statements and recommendations. Where consensus was not achieved, the Facilitators sought to ensure that the work product reflected the views expressed in the workgroup.

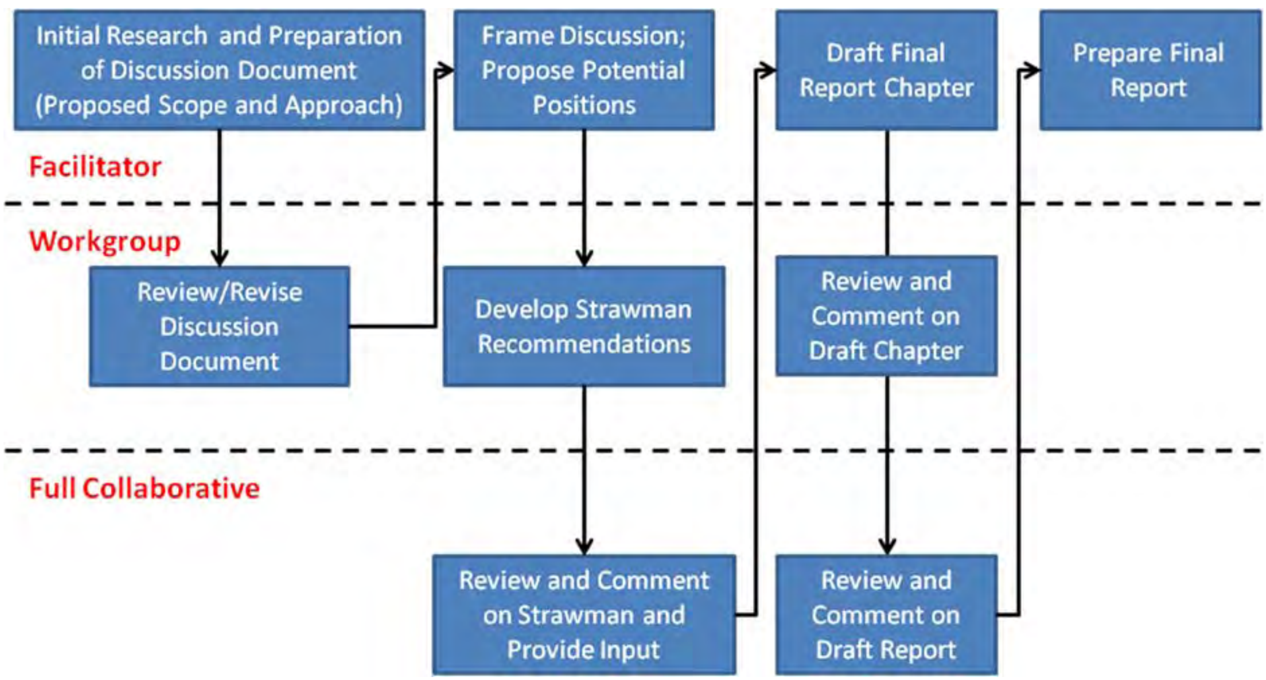
Each workgroup met for a period of several months. After a series of meetings conducted in person, or through video and audio conference calls and web exchanges, proposed content was drafted by the workgroup and prepared for presentation to the full Collaborative. Each workgroup's strawman content was reviewed and discussed by the full Collaborative in one or more of the nine public full ISSGC Workshops that were conducted during the 20 months of Collaborative effort. These workshops featured updates on national smart grid developments,

[28] Docket 07-0566, Order at 142

presentations on a variety of smart grid issues, panel discussions by stakeholders and other experts, as well as discussion of proposed content for this Report as drafted by the workgroups.[29]

The full Collaborative was invited to submit comments and suggested edits to the workgroup drafts, which were then considered and incorporated by each workgroup into its final work product, a draft report chapter. The draft chapters were then circulated to stakeholders for final consideration. In some cases this final consideration required renewed workgroup activity to ensure that the Collaborative Report fully reflects stakeholder views.

This chart depicts the flow of work that went into preparing each of the major chapters of this Report:



The following chapters of this Report present detailed examinations of key smart grid topics together with related policy recommendations wherever consensus among participants in the Collaborative was achieved. In those cases where disagreements about policy issues could not be resolved, this Report describes those disagreements in lieu of presenting a recommendation.

The Collaborative process was lengthy and sometimes arduous, but transparent and inclusive throughout. As a product of the collective work and wisdom of stakeholders in the Illinois electricity system, this Collaborative Report attempts to provide a timely compendium of smart

[29] In addition to email circulation of various drafts and materials, the facilitator created a web site where resources and documents used by the Collaborative are posted: http://www.ilgridplan.org/default.aspx.

grid analysis in keeping with the Commission's goal of considering smart grid issues "in a deliberate and thorough, yet expedited manner."[30]

[30] Docket 07-0566, Order at 140

Smart Grid Definition

First on the Commission's list of foundational policies to be addressed by the Collaborative is the "definition of a smart grid and its functionalities." (07-0566 Order at 141).

A comprehensive smart grid definition includes the concepts of what a smart grid is – its underlying technologies, and what a smart grid does – its functional capabilities. Stakeholders did not reach consensus on a "definition of a smart grid"; however, they agree that it encompasses a variety of technologies (for example, distribution automation and automated metering infrastructure), a variety of characteristics (for example, self-healing and capable of real-time data updating), and a variety of policy options (for example, dynamic pricing and energy efficiency programs). Stakeholders examined descriptions of smart grid used by DOE and in federal law as detailed below, but the Collaborative did not independently write a definition.

In developing its "Modern Grid Strategy," the U.S. Department of Energy's National Energy Technology Laboratory (NETL) convened a group of stakeholders representing utilities, technology companies, regulators, researchers and consumers. Together they identified the following seven characteristics of a smart grid, all of which focus on the functionality of an ideal smart grid:

1. Enables Active Participation by Consumers in Demand Response
2. Accommodates All Generation and Storage Options
3. Enables New Products, Services, and Markets
4. Provides Power Quality for the Range of Needs in a Digital Economy
5. Optimizes Asset Utilization and Operating Efficiency
6. Addresses and Responds to System Disturbances in a Self-Healing Manner
7. Operates Resiliently Against Physical and Cyber Attacks and Natural Disasters.

The Energy Independence and Security Act of 2007 requires each state to "consider" utility investment in smart grid, and includes the following "Statement of Policy on Modernization of Electricity Grid" (Section 1301):

> *It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a Smart Grid:*
>
> 1. *Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.*
> 2. *Dynamic optimization of grid operations and resources, with full cyber-security.*
> 3. *Deployment and integration of distributed resources and generation, including renewable resources.*
> 4. *Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.*

5. *Deployment of ‘‘smart’’ technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.*
6. *Integration of ‘‘smart’’ appliances and consumer devices.*
7. *Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.*
8. *Provision to consumers of timely information and control options.*
9. *Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.*
10. *Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.*

Section 1306 of EISA defines “smart grid functions” as:

1. *The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations, to or from or by means of the electric utility system, through one or a combination of devices and technologies.*
2. *The ability to develop, store, send and receive digital information concerning electricity use, costs, prices, time of use, nature of use, storage, or other information relevant to device, grid, or utility operations to or from a computer or other control device.*
3. *The ability to measure or monitor electricity use as a function of time of day, power quality characteristics such as voltage level, current, cycles per second, or source or type of generation and to store, synthesize or report that information by digital means.*
4. *The ability to sense and localize disruptions or changes in power flows on the grid and communicate such information instantaneously and automatically for purposes of enabling automatic protective responses to sustain reliability and security of grid operations.*
5. *The ability to detect, prevent, communicate with regard to, respond to, or recover from system security threats, including cyber-security threats and terrorism, using digital information, media, and devices.*
6. *The ability of any appliance or machine to respond to such signals, measurements, or communications automatically or in a manner programmed by its owner or operator without independent human intervention.*
7. *The ability to use digital information to operate functionalities on the electric utility grid that were previously electro-mechanical or manual.*

8. *The ability to use digital controls to manage and modify electricity demand, enable congestion management, assist in voltage control, provide operating reserves, and provide frequency regulation.*

Creating a smart grid with these capabilities requires integration of electric power and delivery technology with computer technology, control technology, telecommunications technology and the internet. In general, the smart grid vision includes significant upgrades to the digital capabilities of the grid and the replacement of older analog technologies with computer-driven and enabled technologies. These technological categories include:

- Digital sensing and measurement
- Automated high speed communication between components of the electric system.
- Automated controls for transmission, distribution and grid repairs
- Advanced storage and peak-shaving technologies
- Automated controls for appliances and consumer devices
- Enhanced management and decision support software.

A list of specific equipment that may be deployed in a smart grid is detailed in Appendix A (Smart Grid Technologies) of this Collaborative Report.

The Collaborative adopts these descriptions of smart grid capabilities and technologies as a useful overview of smart grid, while acknowledging the limitations of their applicability to state regulatory decisions. These descriptions were not created for the purpose of state-level public utility ratemaking, and inclusion of these descriptions in this Report is not intended to suggest or imply any particular regulatory policy or ratemaking treatment of future smart grid investments in Illinois.

Smart Grid Applications

Introduction

One of the key Collaborative tasks identified by stakeholders was to develop a comprehensive list of potential smart grid investments, and to examine them for potential costs and benefits. This task was a response to the first foundational policy identified in the ICC Order creating the Collaborative – a "definition of a smart grid and its functionalities." In this chapter, the Collaborative identifies a wide range of smart grid applications consistent with the description of smart grid discussed in this Report. A discussion of the Collaborative's attempt to define the term "smart grid" is found in the Smart Grid Definition chapter of this Report.

The purpose of identifying the applications was to provide the Commission with a comprehensive catalogue of smart grid applications and to identify the potential sources of costs, benefits and negative impacts associated with each. Although an attempt is made in the chapter to identify qualitatively the potential sources of cost and benefit for a set of smart grid applications, these costs or benefits were not verified or quantified through additional research or analysis. It was determined to be beyond the scope of the Collaborative to pass judgment (positive or negative) on the projected net value of these applications.

The identification of potential benefits and negative impacts was intended to be comprehensive, excluding only those that were clearly not plausible. The reader should not assume that the identification of potential benefits or negative impacts represents a conclusion by the Collaborative that these would necessarily occur as a result of any smart grid deployment.

The realization of potential benefits could be dependent on a number of factors including:

- Existence of supporting and effective business and regulatory models
- Establishment of supportive legislative and regulatory policies
- Extent of participation by the customer and/or other market entities
    - Need for customer incentives
    - Persistence of customer behavior over time
    - Sufficient customer understanding of options and impacts
    - Usage patterns and flexibilities
    - Access to smart- grid enabled devices
    - Customer skepticism, confusion or willingness
- Extent to which functionalities do not duplicate customers' or other market entities' existing equipment or capabilities
- Extent of deployment in a utility's service territory
- Market behavior over time.

In some cases, the identified potential benefits of an application may be offset or negated by the costs of deployment or by other potential negative impacts to Illinois stakeholders. These potential negative impacts are identified in this chapter; however, a more complete discussion of these and other issues that could directly affect consumers is found in the Consumer Policy Issues chapter of this Report.

In addition to the descriptions of smart grid applications and their potential sources of cost and benefit, the Collaborative attempted to map potential benefits for each application to beneficiaries. The mapping exercise does not represent a conclusion by the Collaborative that these benefits would necessarily occur as a result of any smart grid deployment. Rather, the mapping was an attempt to identify, at a high level, what customer groups or market entities might realize the benefits of smart grid deployment. This mapping was done with the understanding that individuals or subgroups of customers might realize potential benefits of a particular smart grid application to greater or lesser degrees. For that reason, potential benefits may need to be mapped and analyzed in greater detail for cost allocation purposes.

Objectives and Purpose

The objectives of this chapter in the Report include the following:

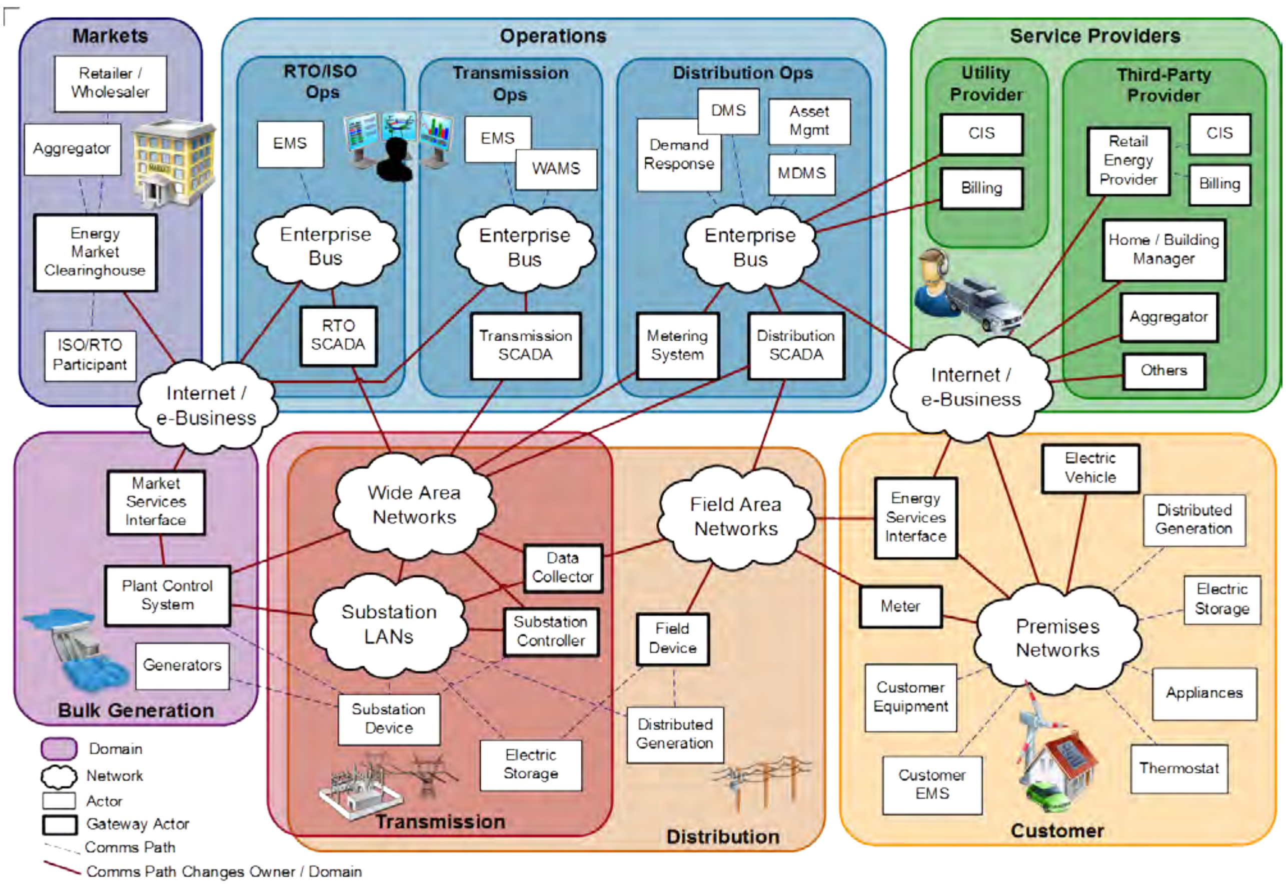
- Provide the Commission with a comprehensive list of investments that could be considered by the electric utilities in Illinois as part of its deployment of smart grid functionalities
- Identify the specific functionalities that could be provided by these investments and the potential sources of benefits to customers, utilities, other electricity market participants (regional transmission operator (RTO), independent system operator (ISO), competitive electric suppliers, and third parties), and society that could result from these investments
- Identify potential negative impacts that could also result from certain applications and technologies
- Provide a mapping between the potential benefits of smart grid applications and expected beneficiaries
- Identify the potential sources of cost associated with these investments
- Provide an informational resource for the Commission on the potential applications and technologies associated with smart grid
- Provide an informational resource and organizational framework for the work of the Collaborative, including the identification of:
    - Primary smart grid applications (input for the development of technical requirements for smart grid)
    - Potential sources of cost and benefit for each application (input for the development of a smart grid cost-benefit framework)
    - Potential beneficiaries of applications implementation (input for the development of a smart grid cost-benefit framework)

- o Potential negative impacts of applications implementation (input for the development of recommended smart grid-related consumer policy issues).

Scope

The focus of this chapter is on smart grid applications. Smart grid *applications* integrate hardware, software, and/or infrastructure (technologies) to deliver defined smart grid functionality and value. Smart grid *technologies* are the hardware, software, and infrastructure building blocks needed for the applications to deliver smart grid functionality/value. (A catalog of smart grid technologies is provided in Appendix A.)

Smart grid applications have the potential to impact the entire electricity value chain – from sources of generation, the growth of other energy resources, energy markets, the transmission grid, the distribution network, to competitive energy suppliers and individual customers. Some applications are limited to a few elements in the value chain while others span many elements. Linking the smart grid elements together requires a robust, two-way communications network. NIST has developed a conceptual reference model for smart grid that depicts the various "domains" that can be impacted by smart grid.



At the direction of the Illinois Commerce Commission, the Collaborative took a broad view of smart grid, identifying smart grid applications and mapping costs, benefits and potential beneficiaries without regard to the Commission's jurisdictional limitations. The inclusion of smart grid applications that would primarily impact elements of the value chain outside of the Commission's jurisdiction carries with it no assumption that cost recovery for these investments would be limited to jurisdictional delivery service ratepayers. Rather, this broader perspective was adopted to provide the Commission with a comprehensive understanding of the potential of smart grid and the need for collaboration and cooperation among market participants and regulators across all of the smart grid domains.

Smart grid is an evolving concept. Although every effort was made to identify a comprehensive set of smart grid applications and technologies in this chapter, it should be understood that new smart grid applications and technologies will be developed over time. Therefore, the list of applications and technologies identified and discussed herein should not be considered exhaustive or definitive.

Definitions

The focus of this chapter is on smart grid applications. Smart grid *applications* integrate hardware, software, and/or infrastructure (technologies) to deliver defined smart grid functionality and value. Smart grid *technologies* are the hardware, software, and infrastructure building blocks needed for the applications to deliver smart grid functionality/value. (A catalog of smart grid technologies is provided in Appendix A.) To facilitate understanding of the following sections, some additional definitions and clarifications are provided.

Potential benefits

Potential benefits are identified as those outcomes of an application deployment that could have value for a customer, utility (in its transmission and distribution functions), RTO/ISO, competitive supplier, third party (including government), and/or society.

- For customers, the potential benefits realized by individual electricity consumers in Illinois, include reductions in customer costs for electric delivery service and energy supply service, and decreases in outages and improved power quality
- For distribution and transmission utilities, value is recognized in benefits that would work to reduce costs, improve system reliability, increase levels of customer satisfaction, optimize assets, and/or mitigate risk
- For regional electricity markets, value is recognized through the reduction in regional energy and/or capacity prices
- For competitive suppliers, third parties, and government, value is recognized through enabling the creation of new value-adding products/services for customers or residents
- For RTOs/ISOs, value is recognized through increased grid stability, improved system awareness, improved forecasting, and more competitive markets for ancillary services

- Societal value is realized by society as a whole, not necessarily Illinois electricity consumers (e.g., environmental benefits, improvements to public health and safety, economic development, and improvements to or the expansion of broadband communications networks).

Potential benefits described in this chapter are those that the particular application is intended to produce. It was beyond the scope of the Collaborative to quantify (positive or negative) the projected net value of smart grid applications. However, the Collaborative did differentiate between *primary* and *secondary* benefits.

- A **primary benefit** is defined to be a significant contributing factor to the positive, value-creating elements of the application. Primary benefits are those that represent the likely motivations behind a decision to evaluate an application for deployment.
- A **secondary benefit** is supplemental to any other positive factors/benefits of the application or could be ancillary to or a byproduct of a primary benefit. As a standalone factor, a secondary benefit would not likely be sufficient to justify application deployment.

Categories of Potential Benefits for Customers

- **Reduced energy usage (efficiency)** – This benefit is achieved indirectly by making the customer aware of the energy usage and energy costs of various appliances or devices at their premises and encouraging the customer to improve efficiency.
- **Reduced energy usage (conservation)** – Conservation is achieved when the customer reduces their energy consumption and does not shift the saved energy usage to another time. This benefit is achieved by making the customer more aware of their energy usage and costs and inducing them to change their energy consumption patterns.
- **Improved information availability to the customer** – This generic benefit can apply to any scenario where the customer is provided with information that is useful to the customer. Examples are: notifying the customer about power outages, feedback on a price based demand response event and provide customers with information about current generation sources.
- **Increased ability to manage energy cost** – This benefit assumes that providing more detailed information about energy usage and costs to the customer will allow them to make better decisions about how and when they use energy.
- **Enhanced services to the customer** – This benefit is achieved by enhancing existing or providing new services to the customer. The service may be provided by the utility, a competitive supplier, private sector third party or a governmental entity.
- **Facilitated integration of customer generation** – This benefit is achieved by facilitating the integration and operation of customer owned generation devices.

- **Improved system reliability** – This benefit applies to any scenario where outages affecting the customer are reduced in frequency or duration of occurrence, including associated health and safety improvements.
- **Improved power quality** – This benefit occurs when the utility is able to detect and correct power quality problems or by decreasing the number of distribution fault current events to which a customer is exposed.

Categories of Potential Benefit for Utilities

- **Increased field labor productivity** – This benefit occurs when automation, communications or efficiency improvements reduce utility field labor costs.
- **Reduced back office support costs** – This benefit occurs when automation, communications or efficiency improvements reduce utility back office costs.
- **Improved system reliability** – This benefit occurs for reductions in frequency or duration of outages.
- **Improved forecasting and modeling** – This benefit is achieved by improving the accuracy of the utility's load predictions and electric system modeling. This benefit can represent both long and short term forecasts.
- **Improved situational awareness** – This is an improvement in the utility's real time visibility for the electric system's status allowing for quicker identification and resolution of system performance issues.
- **Extended asset life** – This benefit occurs for extending the useful life of any utility electrical system assets by reducing stress on those assets and improving maintenance.
- **Reduced failure rates** – This benefit occurs for reducing asset failures, especially of electric system components.
- **Improved asset performance** – This benefit occurs if system assets can be made to perform more efficiently.
- **Improved employee safety** – This benefit typically occurs by reducing the amount of time employees spend in the field.
- **Reduced non-energy procurement cost** – Procurement costs can be reduced by having better data to correctly size a new or replacement asset and improving the ability to plan for new or replacement assets.
- **Reduced line losses** – Line losses can be improved by correcting power factor, lowering voltage, and correctly sizing and siting utility equipment.
- **Reduced lost revenues (theft)** – This benefit is achieved by stopping, deterring or detecting theft.
- **Reduced lost revenues (unbilled)** – This benefit is achieved by reducing unbilled energy delivered.

- **Improved collections or cash flow** – This benefit is achieved by increasing the collection rate of late payments and no payments. This may not be a utility benefit due to the customer uncollected bill tariff that is now in place in Illinois.
- **Deferred investments or enhancements** – This benefit occurs when the utility can extend current systems and assets to meet future needs.

Categories of Potential Benefit for Regional Electricity Market

- **Reduced energy supply and capacity prices** – These benefits can result from changes in the magnitude or timing of electricity demand and deferrals or reductions in transmission and generation investment.

Categories of Potential Benefit for Competitive Suppliers and Third Parties

- **Improved or expanded products and services** – This benefit occurs when new services or products are accommodated by smart grid technology or when competitive suppliers and third parties receive more customer data, higher resolution data, or customer data that provides the competitive suppliers and third parties with opportunities to offer new or improved services.

Categories of Potential Benefit for RTO/ISO

- **Increased grid stability** – This benefit occurs by reducing the frequency and duration of transmission level outages that affect the RTO / ISO.
- **Improved situational awareness** – This is an improvement in the RTO / ISO's real time visibility for the electric system's status allowing for quicker identification and resolution of system performance issues.
- **Improved forecasting and modeling** – This benefit is achieved by improving the accuracy of the RTO / ISO's load predictions and electric system modeling. This benefit can represent both long and short term forecasts.
- **Improved settlement process** – This benefit occurs if there are efficiency and effectiveness improvements in the RTO/ISO's settlement process.
- **Increased market competitiveness (ancillary services)** – This benefit occurs through the expansion of participants in the market for ancillary services.

Categories of Potential Societal Benefit

- **Increased use of renewables** – With better information, load can be more readily shifted to occur when preferred renewable generation output is higher and new grid functionalities can facilitate incorporation of renewable resources into the supply portfolio.

- **Reduced carbon dioxide emissions** – Carbon emissions are assumed to slightly decrease by reducing utility vehicle miles or reducing system load that depends on carbon based generation.
- **Improved air quality** – This benefit primarily occurs if coal generation can be reduced.
- **Improved public health and safety** – This benefit is generally achieved by reducing the frequency and duration of outages.
- **Improved economic productivity** – This benefit is generally achieved by reducing the frequency and duration of outages.
- **Improved system resiliency (disaster recovery)** – This benefit is generally achieved by reducing the frequency, duration and scale of outages.
- **Improved broadband/communications network** – This benefit is generally achieved through improvements to, or the expansion of, broadband/communications networks in connection with the development of the smart grid.

Beneficiaries

A beneficiary is the entity that would initially realize the benefit of an application. Benefits initially realized by utilities are assumed to accrue to customers either automatically or through specific regulatory actions that pass benefits along to customers.

The Collaborative designated six categories of beneficiaries for the purpose of mapping benefits to beneficiaries:

- Customers
- Utility
  - Distribution
  - Transmission
- Regional Electricity Markets
- Third-parties/competitive suppliers
- RTO/ISO
- Society.

For the purpose of recognizing differences in kind and magnitude of potential benefits associated with an application for different types of customers, the following customer groups were identified:

- **Residential / Small Business** – Customers served through the distribution system and eligible for supply service from the utility through approved Illinois Power Agency procurement plans
- **Medium Sized Businesses** – Served through the distribution system and with supply service that has been declared competitive; may or may not have AMI meters, but will not have service switches

- **Large Businesses** – Served at transmission system voltage and would benefit from any utility efficiencies and market improvements due to smart grid functionalities.

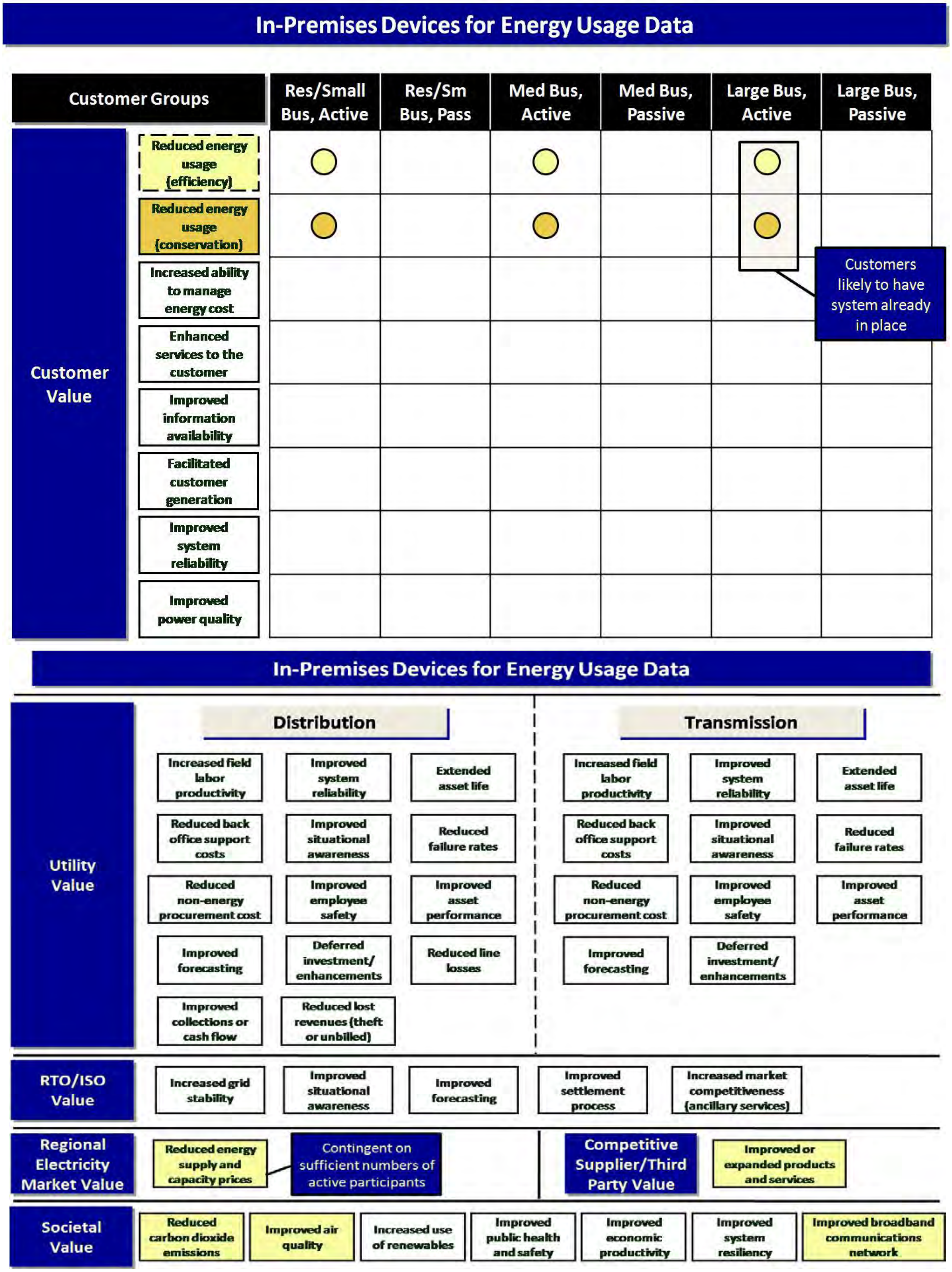
Within each group of customer classes, participants can be further broken down into “active” and “passive” participants:

- **Active Participants** – those customers who would utilize AMI and other smart grid technologies and applications to participate in new rate structures. Active participants also receive passive participant benefits
- **Passive Participants** – all other customers who might benefit from any utility smart grid efficiencies and market improvements.

Even within these segments, subgroups or individual customers may realize specific benefits to greater or lesser degrees. For that reason, potential benefits may need to be mapped and analyzed in greater detail for cost allocation purposes.

Consistent with the above definitions, a graphical representation was prepared for each application depicting the potential source of primary and secondary benefits and a mapping of these benefits to beneficiaries. The following graphics are representative of those used in the following section of the Report. Primary benefits are depicted with darker, amber-shaded boxes; secondary benefits are depicted with yellow-shaded boxes.

These graphical representations are intended to provide a simple way to illustrate how the potential benefits are mapped for each application; however, no inference should be drawn that the mapped potential benefits would necessarily be realized.


In-Premises Devices for Energy Usage Data
Customer Groups
Res/Small Bus, Active
Res/Sm Bus, Pass
Med Bus, Active
Med Bus, Passive
Large Bus, Active
Large Bus, Passive
Customer Value
Reduced energy usage (efficiency)
Reduced energy usage (conservation)
Increased ability to manage energy cost
Enhanced services to the customer
Improved information availability
Facilitated customer generation
Improved system reliability
Improved power quality
Customers likely to have system already in place
In-Premises Devices for Energy Usage Data
Distribution
Transmission
Utility Value
Increased field labor productivity
Improved system reliability
Extended asset life
Reduced back office support costs
Improved situational awareness
Reduced failure rates
Reduced non-energy procurement cost
Improved employee safety
Improved asset performance
Improved forecasting
Deferred investment/ enhancements
Reduced line losses
Improved collections or cash flow
Reduced lost revenues (theft or unbilled)
Increased field labor productivity
Improved system reliability
Extended asset life
Reduced back office support costs
Improved situational awareness
Reduced failure rates
Reduced non-energy procurement cost
Improved employee safety
Improved asset performance
Improved forecasting
Deferred investment/ enhancements
RTO/ISO Value
Increased grid stability
Improved situational awareness
Improved forecasting
Improved settlement process
Increased market competitiveness (ancillary services)
Regional Electricity Market Value
Reduced energy supply and capacity prices
Contingent on sufficient numbers of active participants
Competitive Supplier/Third Party Value
Improved or expanded products and services
Societal Value
Reduced carbon dioxide emissions
Improved air quality
Increased use of renewables
Improved public health and safety
Improved economic productivity
Improved system resiliency
Improved broadband communications network

Potential Negative Impacts

Potential negative impacts are identified as possible outcomes of an application deployment that could be expected to reduce, or detract from, value to a customer, utility (in its distribution and transmission functions), RTO/ISO, competitive supplier/third party, and/or society. Categories of potential negative impacts, as with benefits, excluding only those clearly not plausible, include:

- Customers
  - Higher utility bills associated with the rollout of smart grid technologies, early retirement of existing utility technologies, purchase of accompanying in-home devices, mandatory and opt out time-of-use pricing structures
  - Increased numbers of disconnections for non-payment
    - Related health and safety issues
    - Customer legal costs for wrongful disconnection
  - Privacy loss related to the production of hourly energy usage data
  - Customer confusion related to increased bills, new pricing structures and utility and third party solicitations
  - Obsolescence risk associated with rapidly evolving digital technology and in-home devices
  - Interference with proper function of customer's electrical equipment
  - Restrained usage associated with real or perceived inability to afford utility service due to mandatory or opt out time-of-use rates
  - Potential consumer fraud associated with third party solicitations
- Utility Operations
  - Increased employee exposure to "backfeed" from increased customer generation and storage
  - Potential increases in undetected energy theft due to decreased service visits
  - Increased legal costs due to additional consumer complaints and disputes
  - Increased customer education costs
- Increased customer service costs associated with customer confusion, complaints and disputes
- Societal/Public Safety
  - Utility job losses
  - Higher number of customers without electric service due to disconnection for non-payment as a result of higher utility bills, remote disconnections and potential prepayment policies

– Increased risk of fire and associated increases in fire protection district budgets due to customer response to increases in customer disconnections.

Potential negative impacts are application-specific and discussed in further detail, by application, in the following section. Additional discussion of potential negative impacts associated with certain applications can be found in the Consumer Policy Issues chapter and the Cost-Benefit Framework chapter.

Smart Grid Applications

The Collaborative identified twenty-eight different smart grid applications. Smart grid applications integrate hardware, software, and/or infrastructure (technologies) to deliver defined smart grid functionality and value. The identified applications were organized into seven categories:

- AMI Applications
- Customer-Oriented Applications
- Demand Response Applications
- Distribution Automation Applications
- Asset/System Optimization Applications
- Distributed Resource Applications
- Transmission Applications.

This section provides a description of each identified smart grid application, a description of the potential sources of cost associated with deploying the application, a description of the potential benefits and beneficiaries of the application, and a description of any potential negative impacts that could be associated with application deployment.

AMI Applications

The AMI applications group encompasses the major features that could be expected of a mature AMI metering system. Different functional options have been separated to facilitate discussion about policy, technical, or cost issues that have significant impact on the specific application. It is not necessary or required to implement all application functions in an AMI metering system. Communications by an AMI meter to in-premises devices is typically identified as a major feature of AMI but for this analysis was kept separate in recognition that communications could be enabled by technologies other than AMI.

The AMI applications are:

- Core AMI Functionality
- Remote Connect/Disconnect
- Outage Management Support
- Power Quality/Voltage Monitoring at the Meter Monitoring at the Meter
- Customer Prepayment Utilizing AMI.

Core AMI Functionality

Description

AMI metering allows the utility to collect usage data from customers more frequently and supports time differentiated interval measurement. These new measurement capabilities allow for new rate structures and can support increased customer awareness of energy usage.

Data from AMI meters can be used by the utility to support other smart grid applications. AMI meters can optionally include a customer owned network interface to support demand response applications and increased customer awareness of energy prices and other information.

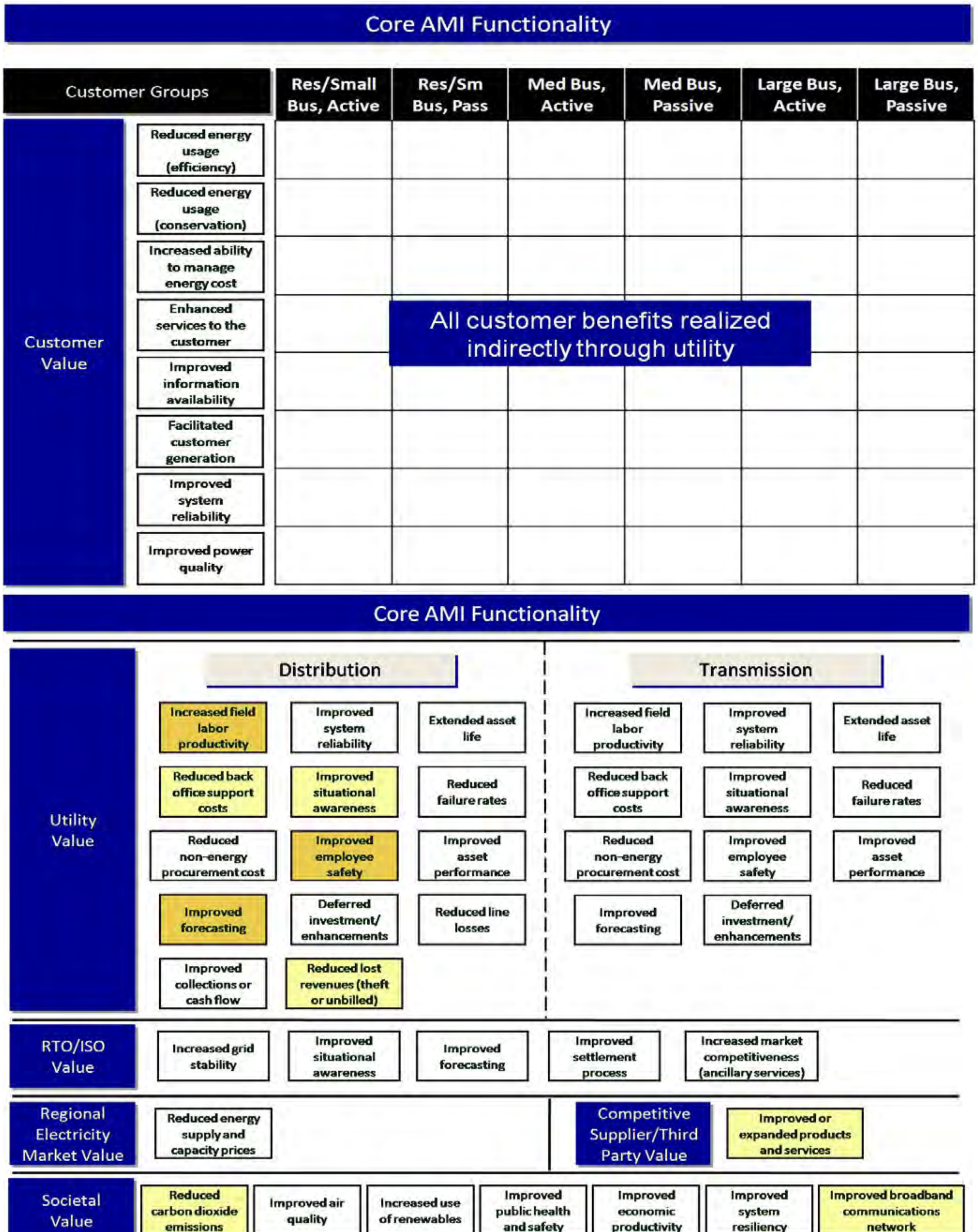
AMI Meters reduce some traditional theft and tamper opportunities that can be used against electro-mechanical meters. Additionally, AMI Meter data can be analyzed to discover potential occurrences of theft. The Core AMI application provides several direct potential benefits to utilities; however, it is also a foundation for other smart grid applications that can provide direct potential benefits to customers, assuming active customer participation in monitoring, shifting and reducing their energy usage.

Potential Sources of Cost

The initial direct costs of an AMI system include the following major components:

- AMI Meters
- AMI Network – the communications infrastructure to communicate with the AMI meters. The AMI network can include multiple networks to support different geographic conditions and customer meter densities found in the utility's service territory. The AMI network may leverage existing utility or public communications networks. The AMI network may also be used by other utility devices supporting new smart grid functions
- AMI Management System – a system to manage data collection, communications with AMI meters, AMI system health, AMI meter firmware upgrades, and AMI meter configuration settings
- Meter Data Management System (MDMS) – a system which stores the data recorded by the meter and provides it to other utility systems, such as billing. Many smart grid applications can be enhanced by the use of data that is provided by AMI meters, and the MDMS serves as a clearinghouse for the AMI data
- Costs associated with early retirement of existing meters.

Potential Sources of Benefits and Beneficiaries



The following primary potential benefits of Core AMI Functionality have been identified:

- **Utilities**
  - Increased field labor productivity – The Core AMI application removes the need for the utility to regularly send workers into the field to collect energy usage data from meters. Utility workers may still be required to manually read some meters in special circumstances
  - Improved employee safety – Removing workers from regularly traveling in the field reduces the opportunity for vehicle accidents, accidental injuries, injuries by animals and incidents on private property
  - Improved forecasting – The interval metering capability of the AMI system provides the utility with a significant improvement in system wide energy usage visibility. Energy usage can be more clearly understood both by time of use and by location.

Potential secondary benefits of Core AMI Functionality could include:

- **Utilities**
  - Reduced back office support costs – Interval meter data can be provided to customers in a manner that helps the customer understand when they are using electricity. If customers have increased understanding about their bill and how they use energy, they may be less likely to contact the utility. Additionally, the utility's ability to read meters at any time may dramatically reduce the need for bill estimating, off cycle billing reads, and other billing process exceptions that increase back office costs
  - Reduced lost revenues (theft) – An AMI metering system can provide several methods to detect meter tampering and provide indications that energy theft may be occurring. Additionally, AMI meters are less vulnerable to some traditional theft techniques. AMI metering by itself cannot eliminate theft; a comprehensive process is needed where the meter records and reports data to the utility, a system analyzes the data and provides an indication to utility personnel for the need to investigate
  - Improved situational awareness – Related to the improved forecasting benefit, AMI meters with an on demand read capability provide the utility with the ability to understand when and where energy is being used. The ability of the meter to support situational awareness is more fully described in other applications
- **Competitive Suppliers or Third Parties**
  - Improved/expanded products and services – Interval energy usage data may allow competitive suppliers or other third parties to offer new rate programs or other energy services that depend on more discrete data than is available today
- **Society**

- Reduced carbon dioxide emissions – This benefit attributable directly to meter installation is likely to be minor and for this specific application is obtained by the reduction in the utility's use of vehicles for their meter reading workforce
- Improved broadband/communications network – This benefit may be achieved if public communications networks are expanded or improved as part of the smart grid system, thereby increasing access or improving functionality.

Potential Negative Impacts:

Major concerns for this application relates to the implementation of pricing programs associated with interval usage data and the cost of accelerated replacement of legacy meters with AMI meters. In addition, stakeholders are concerned generally about customer data privacy and access and use of customer data by third parties. AMI meters record customer usage in more discrete time intervals, typically 15 minutes to an hour. There is a concern that unsecured customer data could be used by unauthorized persons to determine when customers are not at home, or to discover how customers use electric devices within their home. In addition, by eliminating the need for manual reading of meters, it is possible that hazardous conditions currently noted by meter readers could go undetected. These and other issues related to data privacy and data access are discussed in detail in the Consumer Policy Issues chapter.

Remote Connect/Disconnect

Description:

AMI meters can be equipped with remotely operable integrated service switches. The utility can open or close the switch by sending a signal to the meter. The utility operates the switch for purposes of customer requested service connection and disconnection or for disconnection for non-payment and reconnection after payment is received. The service switch may also be used by the utility to disconnect power as requested by official emergency personnel in the event of an emergency such as a house fire.

Not all AMI meters can be equipped with a remote service switch. For the purpose of this analysis, it is assumed that single phase meters at 240 volts or lower are capable of being fitted with an integrated service switch.

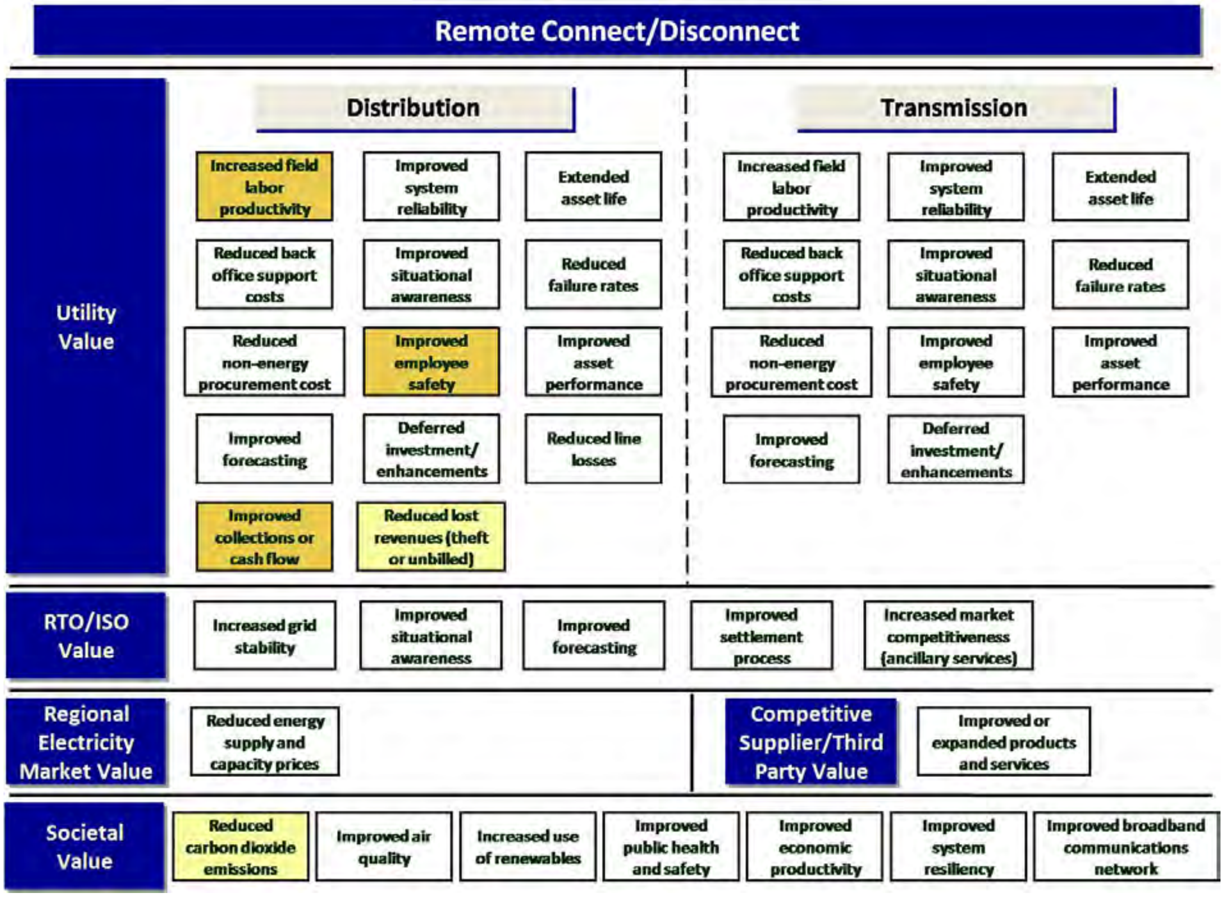
This application is dependent on the presence of the Core AMI application. This application was considered separately from the Core AMI because it is an additional option provided by AMI vendors and there are public policy issues concerning how and when the service switch can be used.

Including a remote service switch in AMI meters is a well understood option, with switches typically rated for 10,000 or more lifetime operations.

Potential Sources of Costs:

This application requires the AMI meter to contain an integrated service switch. Additional costs may be incurred to meet new security requirements.

Potential Sources of Benefits and Beneficiaries:



Remote Connect/Disconnect

	Customer Groups	Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer	○	○				
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						

The following primary potential benefits of Remote Connect/Disconnect have been identified:

- **Utilities**
  - Increased field labor productivity – The utility would no longer be required to dispatch a field crew to perform service connections and disconnections
  - Improved employee safety – Utility personnel would spend less time in the field reducing opportunities for vehicle accidents, accidental injuries, injuries by animals and incidents on private property
  - Improved collections or cash flow –. Automating the disconnect function provides the utility with the ability to disconnect customers in a consistent manner and prevent additional usage from accruing.

Potential sources of secondary benefits could include:

- **Utilities**
  - Reduced unbilled revenues – Customer requested disconnections, as when moving out of their premises, may not occur in a timely fashion under existing work processes. Energy usage that occurs before a new customer moves in may either be unbilled or billed to customers in a non-equitable manner
- **Society**
  - Reduced carbon dioxide emissions – This benefit is likely to be minor and for this specific application is obtained by the reduction in the utility's use of vehicles for their meter reading workforce
- **Customers**
  - Enhanced services to customers – Customers requesting either a service connection or disconnection can expect that the automated process will allow a service change to occur promptly.

Potential Negative Impacts

There are several potential negative impacts associated with remote service switches. The most significant concern has to do with the use of remote disconnection for non-payment, and the potential for negative customer safety and health impacts and increased public safety costs due to customer responses to lost access to electricity service. There is a concern that the ability to remotely disconnect customers for non-payment may result in customer payment agreements that are fewer in number and less favorable to customers. These issues are more fully explained and addressed in the Consumer Policy Issues chapter. Other concerns include erroneous or unauthorized disconnections.

Outage Management Support

Description

AMI Meters can report power outage and power restoration messages to the utility allowing the utility to improve its ability to determine the scope and location of an outage, to improve outage response, and to verify that all affected customers are restored.

Utilities currently have outage management systems (OMS) that receive input from distribution or transmission system devices and customer phone calls and perform a predictive analysis to determine the location of the outage. AMI meters can report power outage conditions to the OMS which effectively replaces the role of customer reports and improve the OMS's analysis. Potentially more significant than outage reporting is the ability of the utility to verify that customers have had their power restored.

This application is considered separately from the Core AMI application due to potential technical and system design requirements needed for implementation. Outage and restoration reporting is a mature application with low risk.

Potential Sources of Costs

This application assumes the existence of an AMI metering system. Additional costs are expected for updating the outage management system and potential network design decisions required to increase the reliability of communications during outages.

Potential Sources of Benefits and Beneficiaries

Outage Management Support

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer	○	○	○	○		
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○		
	Improved power quality						

Outage Management Support

Utility Value

Distribution

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements
- Reduced line losses
- Improved collections or cash flow
- Reduced lost revenues (theft or unbilled)

Transmission

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements

RTO/ISO Value

- Increased grid stability
- Improved situational awareness
- Improved forecasting
- Improved settlement process
- Increased market competitiveness (ancillary services)

Regional Electricity Market Value

- Reduced energy supply and capacity prices

Competitive Supplier/Third Party Value

- Improved or expanded products and services

Societal Value

- Reduced carbon dioxide emissions
- Improved air quality
- Increased use of renewables
- Improved public health and safety
- Improved economic productivity
- Improved system resiliency
- Improved broadband communications network

The following primary potential benefits have been identified:

- **Utilities**
  - Increased field labor productivity – Improved outage detection and location can better direct utility workers to the outage location and reduce the amount of time taken patrolling power lines. After repairs are made, using the AMI system to verify restoration to customers can efficiently direct utility workers to additional work sites
  - Improved system reliability – Using the AMI meter system to support the outage management system does not reduce the number of outages, but it could reduce outage duration by allowing the utility to work more efficiently
  - Improved employee safety – Reduces the amount of time that utility workers spend in the field
  - Improved situational awareness – AMI meters can report in near real time, power outage and power restoration messages to the outage management system
- **Customers**
  - Improved system reliability – Some customers will benefit from reduced outage durations.

Potential sources of secondary benefits could include:

- **Utilities**
  - Reduced back office support costs – Increased automation and a reduced need for customer reports
- **Customers**
  - Enhanced services to the customer – Customers can expect that their power will be restored by the utility even if they do not call to report the outage
- **Competitive Suppliers and Third Parties**
  - Improve/expand products and services – Automated outage reporting at the individual customer level could enable new services
- **Society**
  - Reduced carbon dioxide emissions – This benefit is likely to be minor and for this specific application is obtained by the reduction in the utility's use of vehicles for their field workforce
  - Improved public health and safety – if the duration of outages is reduced
  - Improved economic productivity – by reducing the duration of outages.

Potential Negative Impacts

The Collaborative found no negative impacts related to this application.

Power Quality/Voltage Monitoring at the Meter

Description

AMI Meter data can provide the utility with an extensive view of voltage levels throughout the distribution system. AMI Meters may also provide other measurements that allow the utility to evaluate system harmonics and power factor. The ability to achieve the benefits for this application largely depend on the capability of the meter to perform measurements that are not normally associated with traditional metering functionality and the network capacity to transport the additional data.

Measurement of voltage, power factor and harmonics are mature capabilities in high end devices. AMI meters typically incorporate voltage measurement and power factor measurement is increasingly available. Harmonic measurement capabilities may be not be cost-effective to include in the near future for most AMI meters but may be a desired feature for higher end commercial and light industrial meters.

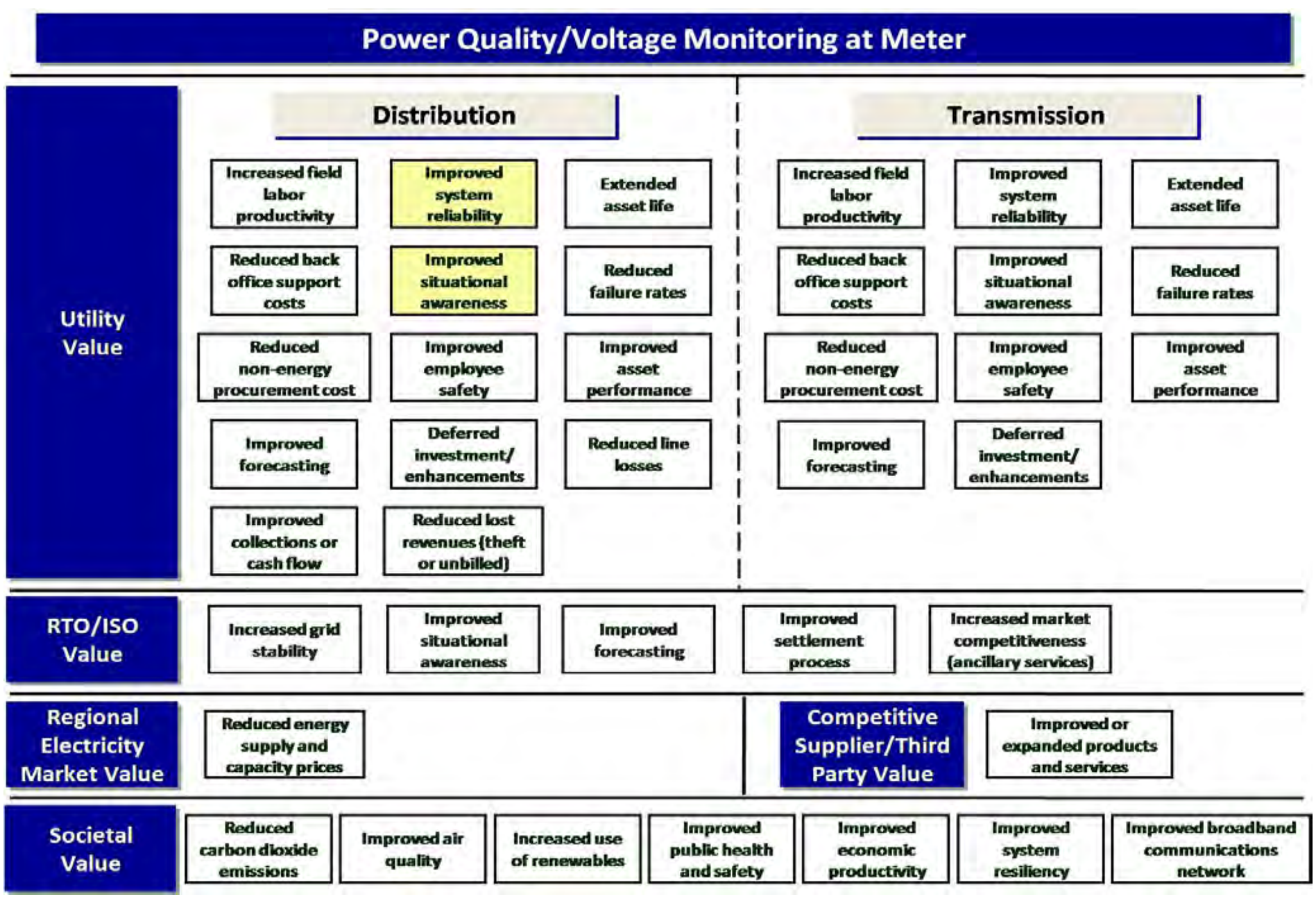
Potential Sources of Costs

The primary costs for this application are for the additional measurement capabilities of the meter and the modifications to back office systems to store and use the data.

Potential Sources of Benefits and Beneficiaries

Power Quality/Voltage Monitoring at Meter

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○		
	Improved power quality	○	○	○	○		



No primary potential benefits were identified.

The following secondary potential benefits are associated with Power Quality/Voltage Monitoring at the Meter Monitoring:

- **Utilities**
  - Improved system reliability – The utility can use the additional meter data to improve distribution operations. Improved situational awareness – The utility can use the additional meter data to improve distribution operations. If the additional meter data is provided in a timely manner, the utility's situational awareness can be improved
- **Customers**
  - Improved system reliability – Improvements in reliability made by the utility also benefits customers as improved reliability
  - Improved power quality – AMI meters with improved measurement capabilities can provide the utility with data that can indicate locations where voltage or other power quality quantities are out of specification. If the utility is able to correct the system issues, then customers' power quality can be improved.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Customer Prepayment Utilizing AMI

Description

A prepayment program provides customers with an option to purchase electricity in advance of its use by purchasing a specified amount of electricity at a specified price. Such programs typically include automatic disconnection of service when the customer's usage exceeds the amount of electricity purchased. Prepayment can serve as an alternative to deposit requirements for utility service, and may reduce the utility's credit and collection costs, as well as provide a structure to assist customers in reducing their electricity usage. However, as detailed below, prepayment for utility service also may have other effects that raise significant social and regulatory issues.

Prepayment offers a potential for reduced electricity bills for participants, only if utility cost savings due to prepayment (billing, collection, and receivables) are greater than the costs of operating the prepayment program and the reduced costs are reflected in participants' rates. Moreover, operation of a prepayment program requires: a) an in-home device to display the customer's actual usage and remaining credit, b) a means by which customers may purchase credits and have them recognized by the device, and c) a link between the device and the utility's meter so that the device can signal the meter and the utility when credit is exhausted or restored. The administrative and equipment costs associated with a prepayment program may be high relative to the small incremental savings realized by the operating utility. However, AMI deployment may reduce or eliminate the need for additional hardware.

This application is very controversial among stakeholders. An assumption was made that prepayment was a voluntary program that would utilize an AMI metering system to provide a communications link between the utility and the customer.

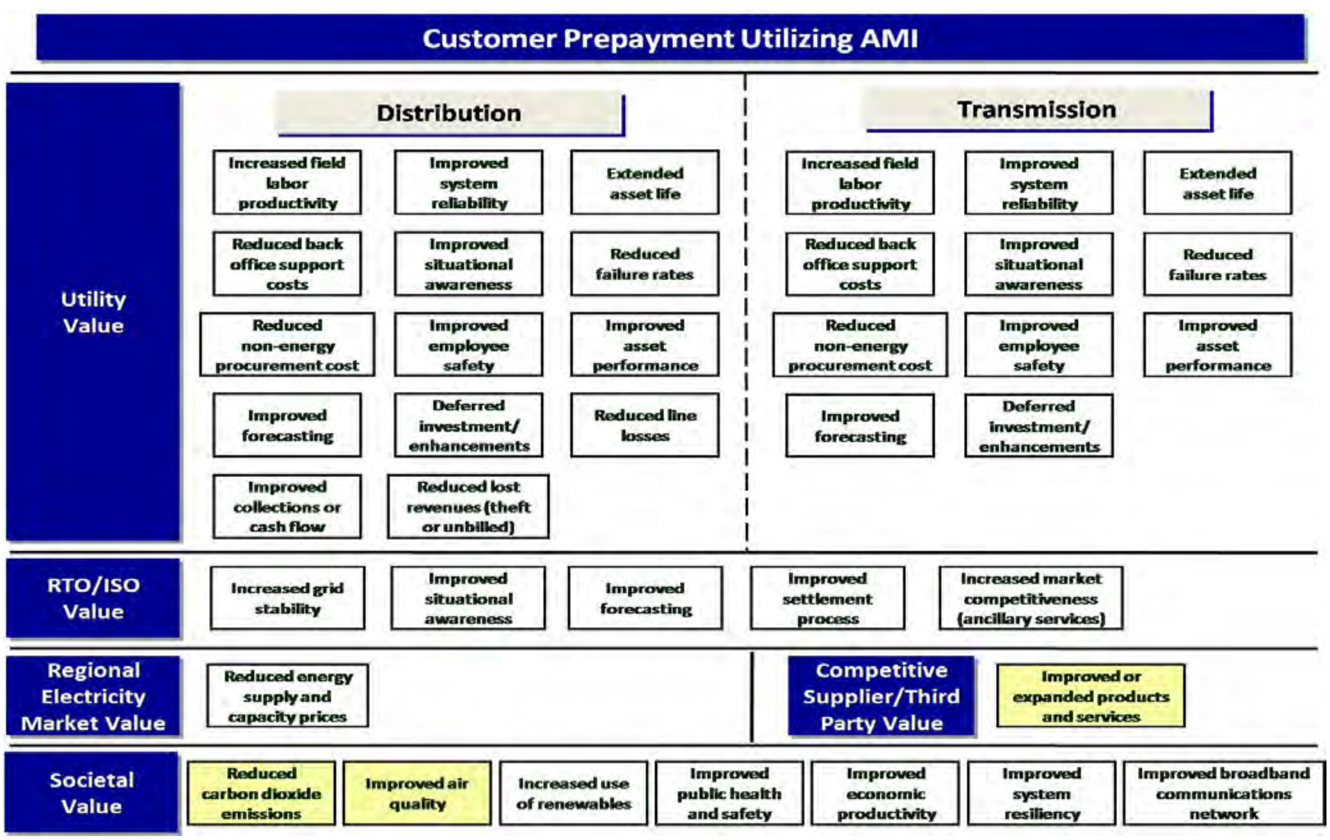
Potential Sources of Costs

This application generally requires an in-premises display device for the customer to view remaining balance or other prepayment related information. The utility will require a modification to their billing system in order to support a prepayment program. Methods for payment and application of payments would also incur additional costs.

Potential Sources of Benefits and Beneficiaries

Customer Prepayment Utilizing AMI

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)	○	○				
	Increased ability to manage energy cost						
	Enhanced services to the customer	○	○				
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						



The following primary potential benefits are associated with this application:

- **Utilities**
  - Improved collections or cash flow - Utilities may benefit from a prepayment program if significant numbers of users utilize the service, especially if the customers are more likely to be late payers
- **Customers**
  - Enhanced services to the customer - Prepayment could serve as an alternative to deposit requirements for utility service.

Potential sources of secondary benefits:

- **Competitive Suppliers and Third Parties**
  - Expanded products and services – Prepayment programs potentially could allow competitive suppliers to devise new options to appeal to customers
- **Customers**
  - Reduced energy usage (conservation) – Customers with in-premises display devices that show the customer how much money they are spending on electricity may reduce usage
- **Society**
  - Reduce carbon dioxide emissions – If sufficient numbers of customers reduce their energy usage, a reduced carbon dioxide emissions can occur. For this application, the effect is likely to be very minor
  - Improve air quality – If sufficient numbers of customers reduce their energy usage and the reduction comes from dirtier generation, air quality can be improved. For this application the effect is likely to be very minor.

Potential Negative Impacts

Prepayment service is a controversial application in the Collaborative with significant potential negative impacts for certain customers. These include issues relating to equitable access to essential services for low income customers, consequences of automatic disconnection when a customer's prepaid balance reaches zero, potential predatory marketing of energy services, potential inappropriate steering of customers to prepayment as well as a concern that the ability to prepay may result in customer payment agreements that are fewer in number and less favorable to customers. Another significant concern has to do with the use of remote disconnection when the customer's balance reaches zero, and the potential for negative customer safety and health impacts and increased public safety costs due to customer responses to lost access to electricity service. These potential negative impacts are addressed in further detail in the Consumer Policy Issues chapter.

Customer-Oriented Applications

The customer-oriented applications group includes applications that communicate data either to the customer or about the customer. The first three applications represent three different communications channels between the customer and utility. These communications channels can be summarized as:

- Communications to an in-premises device
- Communications to a web based application
- Communications by email, text message or mobile device.

The Customer-Oriented Applications are:

- In-Premises Devices for Energy Usage Data
- Customer Web Portal for Energy and Cost Data
- Outage Notification to Customer
- Government and Third Party Use of Customer Data.

In-Premises Devices for Energy Usage Data

Description

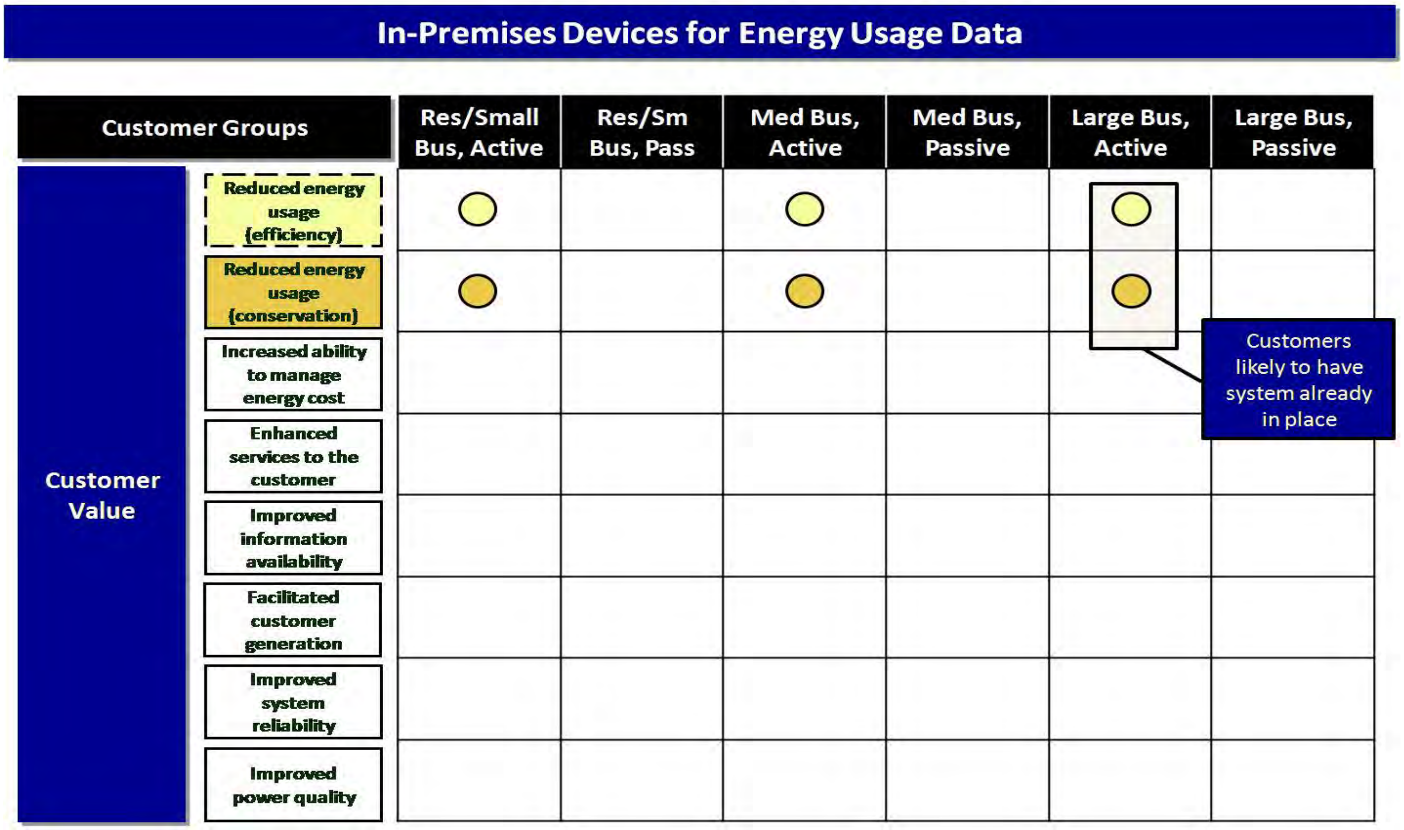
In-premises devices receive and display energy usage information to customers. This information can be used by customers to manage their energy consumption. AMI meters can be used to communicate energy usage data to in-premises devices using a home area network (HAN). Communication to in-premises devices could also be accomplished with other technologies such as pager networks, cellular networks, traditional wired phone services, broadband internet connections or private networks. All listed benefits identified here are dependent upon active customer participation in monitoring, shifting and reducing their energy usage

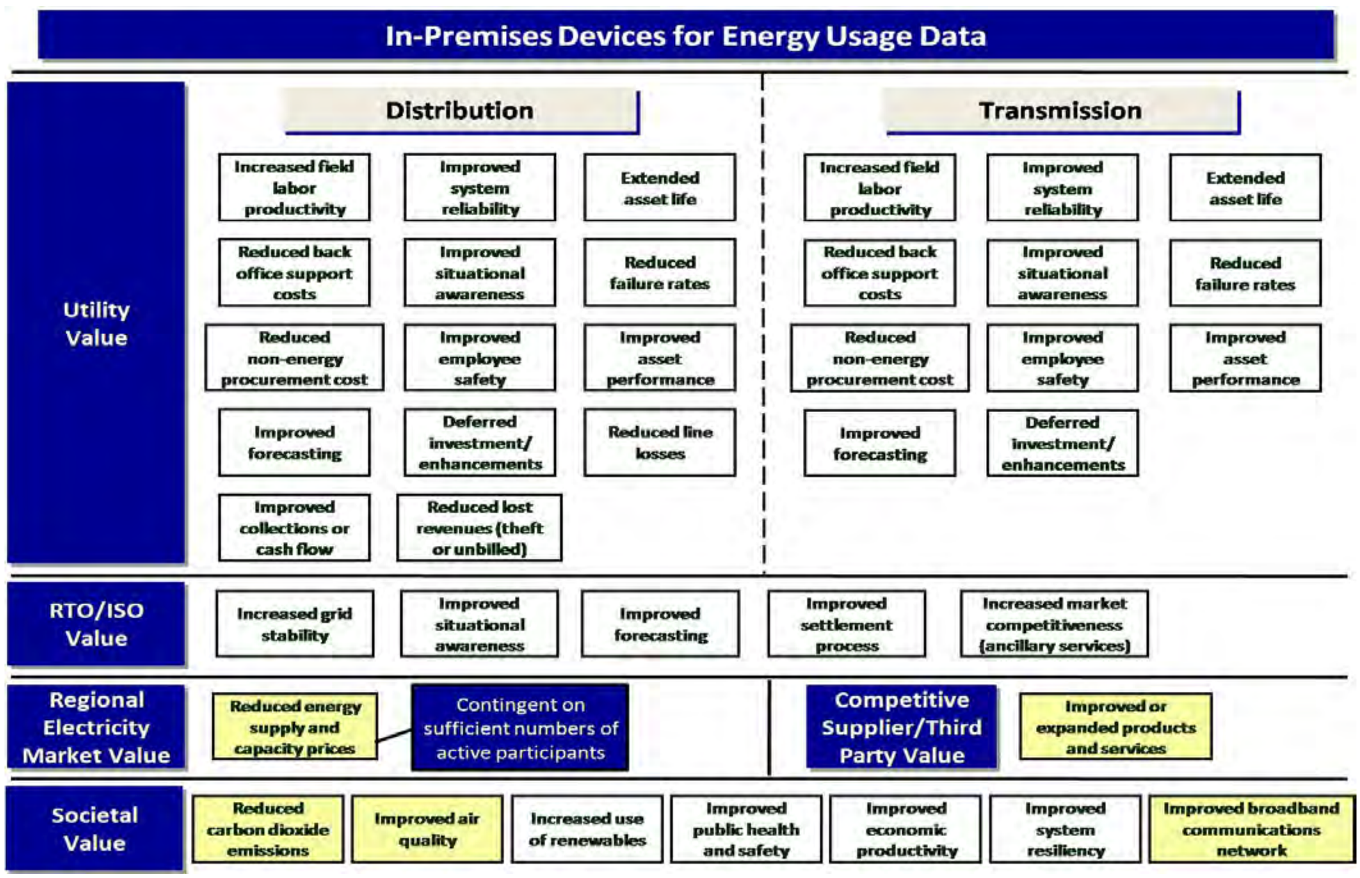
This application includes not only simple display devices but also energy management systems, smart appliances, thermostats and pool pumps. Until national standards are in place, there is a risk of technology incompatibility or obsolescence.

Potential Sources of Costs

There are initial costs for an AMI metering system and any integrated HAN communications capability. There are additional costs for customer devices. Issues associated with acquisition of In-premises Devices (also known as Post-Meter Devices) are discussed in greater detail in the Competitive Retail Market Structure section of the Consumer Policy Issues chapter of this Report.

Potential Sources of Benefits and Beneficiaries





The following primary potential benefits of this application have been identified:

- **Competitive Suppliers and Third Parties**
    - Improves/expanded products and services – By improving communications to the customer, competitive suppliers and third parties could offer new products, rate offerings and energy management services
- **Customers**
    - Reduced energy usage (conservation) – Customers with displays could monitor their energy usage and receive feedback on efforts to conserve energy.

Potential secondary sources of benefits include:

- **Customers**
    - Reduced energy usage (efficiency) – Customers using in-premises devices can analyze the usage of specific devices in their home or business to determine if more energy efficient models are appropriate
- **Regional Electricity Market**
    - Reduced energy supply and capacity prices – if participating customers provide sufficient conservation to significantly modify the system-wide load shape
- **Society**
    - Reduced carbon dioxide emissions – Sufficient penetration and utilization of in-premises devices for home energy management could result in reduced generation using fossil fuels
    - Improved air quality – If sufficient numbers of customers reduce their energy usage and the reduction comes from dirtier generation, air quality can be improved
    - Improved broadband/communications network – This benefit may be achieved if public communications networks are expanded or improved as part of the smart grid system, thereby increasing access or improving functionality.

Potential Negative Impacts

Potential negative impacts include the need for investment, which may be significant, by consumers in in-home devices. These devices could be obsolete before their value has been realized. Other concerns for this application relate to policies covering access to in-premises devices. Issues about who should provide and pay for these devices are discussed in further detail in the Consumer Policy chapter. To the extent load shifting occurs and increases fossil-fueled generation, i.e. shifts usage to periods when fossil fuel units are "on the margin," this has the potential to increase carbon dioxide emissions and, if in sufficient amount, to reduce air quality.

Customer Web Portal for Energy and Cost Data

Description

This application allows customers who cannot or do not already do so through other means, to view their historical energy usage and energy cost data on the internet. A web portal would not provide real time information, but would allow for more descriptive views and comparisons of a customer's energy usage over time. This application includes customers viewing data on a computer by visiting a utility website, more advanced in-premises devices receiving information through the internet, or information-rich emails that the customer receives periodically from the utility or third party. The general expectation is that a customer would be able to view the previous day's energy usage on the website along with additional historical data and an estimated month-to-date bill. Collection of this data is not necessarily dependent on AMI. The benefits listed assume the availability of internet access in customer homes, as well as a commitment to devote time to monitoring energy data provided by the web portal.

Presenting data to customers through a web site is a mature application with low risk.

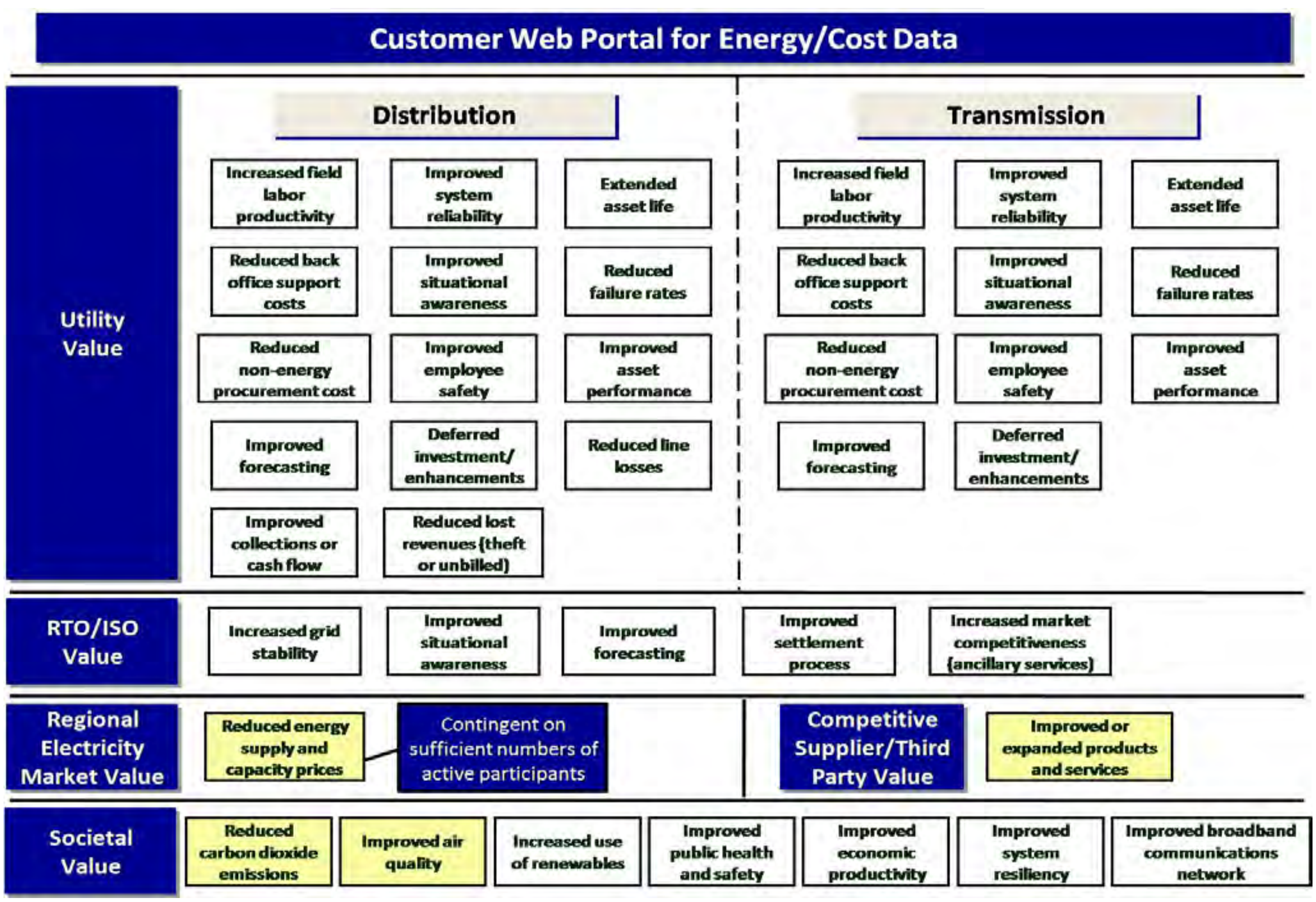
Potential Sources of Costs

The most significant costs for this application are for upgrades to the utility's web servers and customer information systems. The application assumes that customers will use existing computers or in-premises devices to access internet delivered data.

Potential Sources of Benefits and Beneficiaries

Customer Web Portal for Energy/Cost Data

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)	●		●		●	
	Reduced energy usage (conservation)	●		●		●	
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability	●		●		●	
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						



The following primary potential benefits have been identified for this application:

- **Customers**
  - Reduce energy usage (conservation) – Customers could use the provided energy usage data to modify their behavior in response to feedback on energy conservation efforts
  - Improved information availability – Customer would have better access to historical usage data and energy cost information.

Potential secondary sources of benefits include:

- **Customers**
  - Reduced energy usage (efficiency) – Customers monitoring their energy usage may be able to analyze the usage of specific devices in their home or business to determine if more energy efficient models are appropriate
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- if sufficient numbers of customers provide conservation sufficient to modify the system-wide load shape or a reduction in peak energy demand
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Potential new third party products, rates and services could be enabled by more detailed information available to the customer
- **Society**
  - Reduced carbon dioxide emissions – energy conservation resulting from this application could result in reduced need for fossil-fueled generation
  - Improve air quality – If sufficient numbers of customers reduce their energy usage and the reduction comes from dirtier generation, air quality can be improved.

Potential Negative Impacts

To the extent time-of-use rates are employed with this application to achieve the benefits listed above, some customers may see increased bills if participation in conservation and shifting of energy use does not occur. For customers without internet access, additional costs would be incurred to take advantage of this application. There is some concern about potential confusion for customers viewing energy usage data in near-real time and potential discrepancies between viewing "raw" data and billing quality data. Any web portal should make clear that a customer's bill is based on elements other than the current usage information. Cyber security vulnerabilities must be adequately addressed or information could be inappropriately accessed through the web portal and customer privacy could be compromised. In addition, the aforementioned customer privacy concerns associated with the availability to the utility and third parties, of time-of-use customer usage data apply here. To the extent load shifting occurs and increases fossil-fueled generation, i.e. shifts usage to periods when fossil fuel units are “on the margin,” this has the potential to increase carbon dioxide emissions and, if in sufficient amount, to reduce air quality.

Outage Notification to Customer

Description

Using an enhanced outage management system, the utility can inform customers through automated emails, text messages and phone calls of existing outages and estimated restoration times. Customers receiving this information can make better decisions on how to respond to the outages. This application does not depend on AMI for communicating to the customer. An installed AMI system may provide the utility with better information about the scope and nature of the outage. It is assumed that customers can choose to participate in this program voluntarily.

Automated messaging is a mature application with low risk.

Potential Sources of Costs

The costs for this application are utility system upgrades to the customer information system and potentially the outage management system. The utility may have additional costs related to transmitting large numbers of emails, text messages or phone calls. The Collaborative did not consider the cost for customers to receive messages to be significant.

Potential Sources of Benefits and Beneficiaries

Outage Notification to Customer

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer	●		●		●	
	Improved information availability	●	●	●	●	●	●
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						

Outage Notification to Customer

Utility Value

Distribution:
- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements
- Reduced line losses
- Improved collections or cash flow
- Reduced lost revenues (theft or unbilled)

Transmission:
- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements

RTO/ISO Value
- Increased grid stability
- Improved situational awareness
- Improved forecasting
- Improved settlement process
- Increased market competitiveness (ancillary services)

Regional Electricity Market Value
- Reduced energy supply and capacity prices

Competitive Supplier/Third Party Value
- Improved or expanded products and services

Societal Value
- Reduced carbon dioxide emissions
- Improved air quality
- Increased use of renewables
- Improved public health and safety
- Improved economic productivity
- Improved system resiliency
- Improved broadband communications network

The Collaborative agreed that the following benefits were both likely and significant:

- **Customers**
  - Enhances services to the customers – Outage notification is a new service to customers
- **Utilities**
  - Reduce back office support costs – By proactively notifying customers of outages and restoration, the utility could see a reduction in call center costs.

Additional Potential Sources of Benefits and Beneficiaries:

- **Customers**
  - Improve information availability – Customers can be made aware of outages that affect their property even when they are not present
- **Society**
  - Improve economic productivity – If outage restoration times can be reported and are sufficiently accurate, businesses receiving outage notifications can improve their operational decisions. This is a benefit to businesses, employees and customers
  - Improve public safety – Improved outage and restoration notification can improve services to members of society who are vulnerable to a disruption in electric service.

Potential Negative Impacts

A potential negative impact for this application is inaccurate reporting of outages. It is possible that the system could report an outage to a customer whose premises is not affected (false positive) or for the system to fail to determine that a customer's premises is affected and report it to the customer (false negative). Cyber security and customer privacy are additional concerns.

Government and Third Party Use of Customer Data

Description

This application is a high level representation of scenarios allowing customers to choose to share all or a portion of their energy usage data, outage status, appliance energy usage and settings or energy cost data with third parties. The Collaborative assumes that the customer would control access to their data and determine which third parties would be able to view specific types of information. The customers would also be informed of how third parties intended to use data. Most examples for sharing data focused on energy management services that could be provided to customers.

The maturity of this application varies based on the source of the data. Data that is shared by the utility with authorized third parties is mature and has low technical risk. More specific applications that involve in-premises devices communicating information to authorized third parties either through the utility's AMI network or other communication channel are less mature. Home area network communications standards are under development.

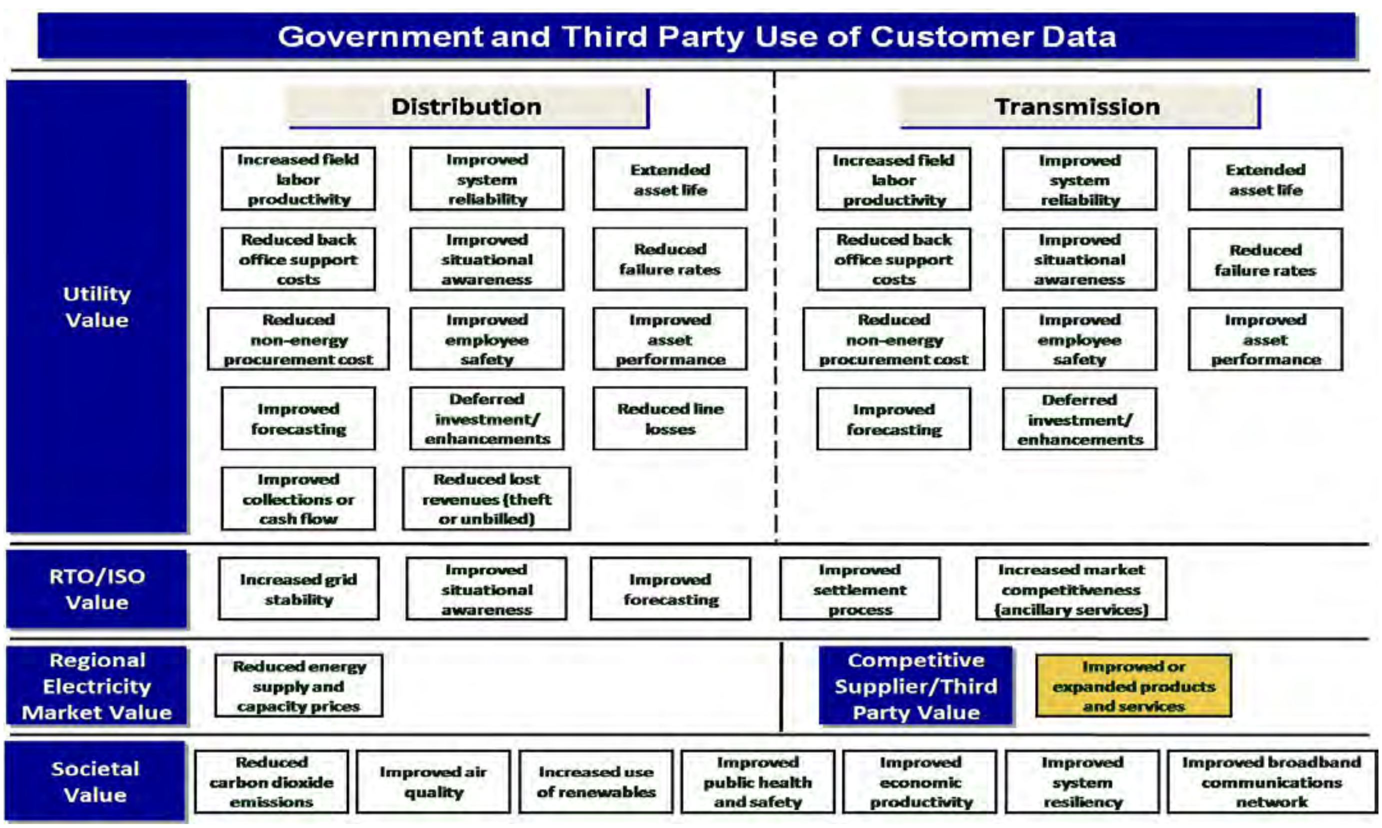
Potential Sources of Costs

This application requires potential upgrades to utility systems to collect, manage and share customer data with third parties. Third parties require systems to receive and use the data. Customers could replace the role of the utility in this application and directly store and transmit data to desired third parties.

Potential Sources of Benefits and Beneficiaries

Government and Third Party Use of Customer Data

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer	○		○		○	
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						



The following primary potential benefits of this application have been identified:

- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – New energy management services can be provided to customers if third parties have access to appropriate data. Services with a data collection component could improve the third parties' understanding of how customers use energy and allow improved service offerings.

Potential secondary sources of benefits include:

- **Customers**
  - Enhanced services to customers – for customers who choose to make their usage information available to third parties.

Potential Negative Impacts

Similar to the Core AMI Metering application, the primary concern for this application relates to customer data privacy associated with the availability to the utility and third parties, including law enforcement officials, of time-of-use customer usage data apply here.

There is a concern that unsecured customer data could be abused by unauthorized persons. Proper network security, information technology practices and privacy policies can be mitigate negative impacts. This issue is further discussed in the Data Privacy and Access section of the Consumer Policy chapter.

Demand Response Applications

The demand response applications group presents four scenarios that use direct signals to the customer or to devices that are enabled to respond. The four signaling types are:

- Price signals
- Direct load control signals
- System measurements
- Environmental signals.

The applications represent several ways in which these different signal types could be used by customers and utilities, but they do not cover every possibility. While participation by customers in demand response activities is assumed to be voluntary, a customer could choose to enroll in a program where participation in a specific event was mandatory.

Demand Response Applications include:

- Pricing Information to In-Premises Devices
- Direct Load Control
- System Frequency Signal to Customer Load Control Devices
- System Renewables Output to Customers.

Pricing Information to In-Premises Devices

Description

Demand response generated by price signals leaves the customer in control of how they wish to participate during periods when energy costs are higher. Price based demand response requires the customer to have more advanced devices if they wish to automate the response than demand response programs based on a simple utility control signal. This application assumes that price based demand response can be as simple as a fixed schedule, tiered, time of use rate or a more dynamic interval based real time price rate. It also includes critical peak pricing and critical peak rebates. More dynamic rate structures may require additional automation of in-premises devices to maximize the application's benefits.

This application is very similar to the In-Premises Devices for Energy Usage application in the nature of benefits that are provided. This application shares many of the same benefit categories with the above application but may provide them to a greater degree.

This technology for this application is not mature but is increasingly becoming more developed as vendors, utilities and standards organizations work to improve home networking technology and devices. Utilities currently have some risk that installed meters implement an in-premises communication solution that is not widely accepted or can't be upgraded to an accepted standard.

Potential Sources of Costs

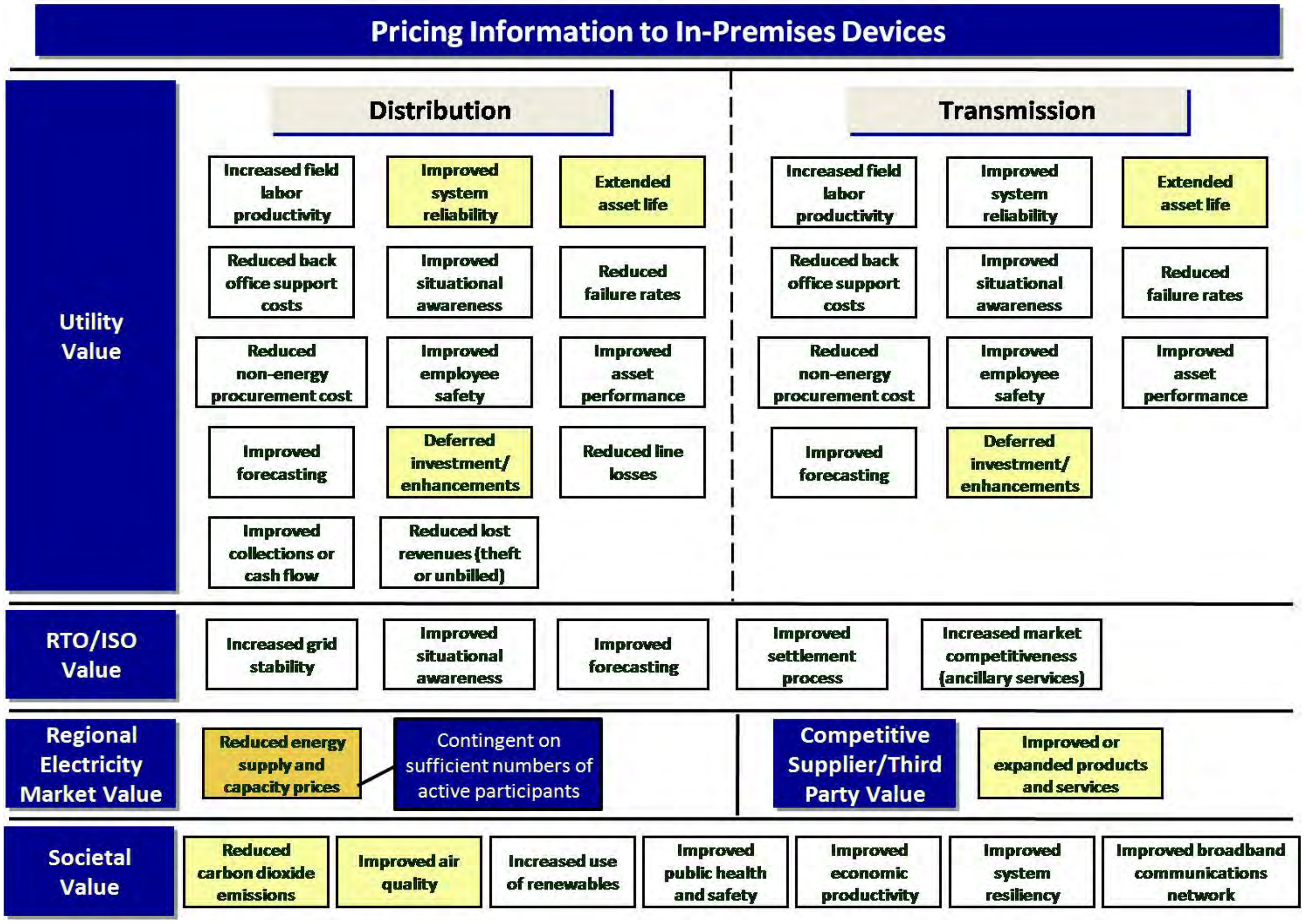
The utility may require a demand response management system for some forms of price based demand response. Additionally, the utility may require customer information system and billing system upgrades. Customers may be required to install in-premises devices for some types of demand response.

Potential Sources of Benefits and Beneficiaries

Pricing Information to In-Premises Devices

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)	●		●		●	
	Increased ability to manage energy cost	●		●		●	
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	●	●	●	●	●	●
	Improved power quality						

Contingent on sufficient numbers of active participants



The following primary potential benefits of this application have been identified:

- **Customers**
  - Reduce energy usage (conservation) – With a price signal, customers can see a more immediate need to reduce energy usage
  - Increase ability to manage energy cost – This assumes that pricing programs provide a financial incentive to the customer to reduce or shift usage to lower energy cost time periods.
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- This benefit assumes that sufficient numbers of participating customers will provide system-wide conservation and shift the entire load curve down, but with a more significant impact of reducing the system peaks if customer responsiveness is sustained over time.

Potential secondary sources of benefits include:

- **Customers**
  - Improved system reliability – Assumes that sufficient customers are responding to price signals by reducing usage at peak times, leading to less wear on electric system components and fewer outages
- **Utilities**
  - Improved system reliability – Assumes that sufficient customers are responding to price signals by reducing usage, leading to less wear on electric system components and fewer outages
  - Extend asset life – Assumes that sufficient customers are reliably responding to price signals by reducing usage over a sustained period of time, leading to less wear on electric system components
  - Defer investment/enhancements – Assumes that sufficient customers are reliably responding to price signals by reducing usage over a sustained period of time, leading to less need for new or larger system components
- **Competitive Suppliers and Third Parties**
  - Improve/expand products and services – Customers participating in price based demand response with third parties may generate higher resolution data than customers who are not participating
- **Society**
  - Reduced carbon dioxide emissions – With sufficient participation and conservation, this benefit assumes that carbon based generation will be reduced
  - Improve air quality – If sufficient numbers of customers reduce their energy usage and the reduction comes from dirtier generation, air quality can be improved.

Potential Negative Impacts

The primary potential negative impact for this application is the impact on customers who are participating in mandatory or opt-out time based rates but cannot limit or shift their electric usage during periods of high energy cost. There is also concern that customers on time-variant rates may overreact to price signals, putting their health and/or safety at risk. To the extent load shifting occurs and increases fossil-fueled generation, i.e. shifts usage to periods when fossil fuel units are “on the margin,” this has the potential to increase carbon dioxide emissions and, if in sufficient amount, to reduce air quality.

Direct Load Control

Description

Demand response can be provided by installing load control devices that receive a signal from the utility to reduce load. Direct control by the utility could be structured to allow the customer to override a demand request.

This application has been widely used by utilities for many years; however newer technologies allow for more flexible implementation and provide better feedback to the utilities. The future vision of this application relies on network technologies and devices that are still in the early stages of deployment.

Potential Sources of Costs

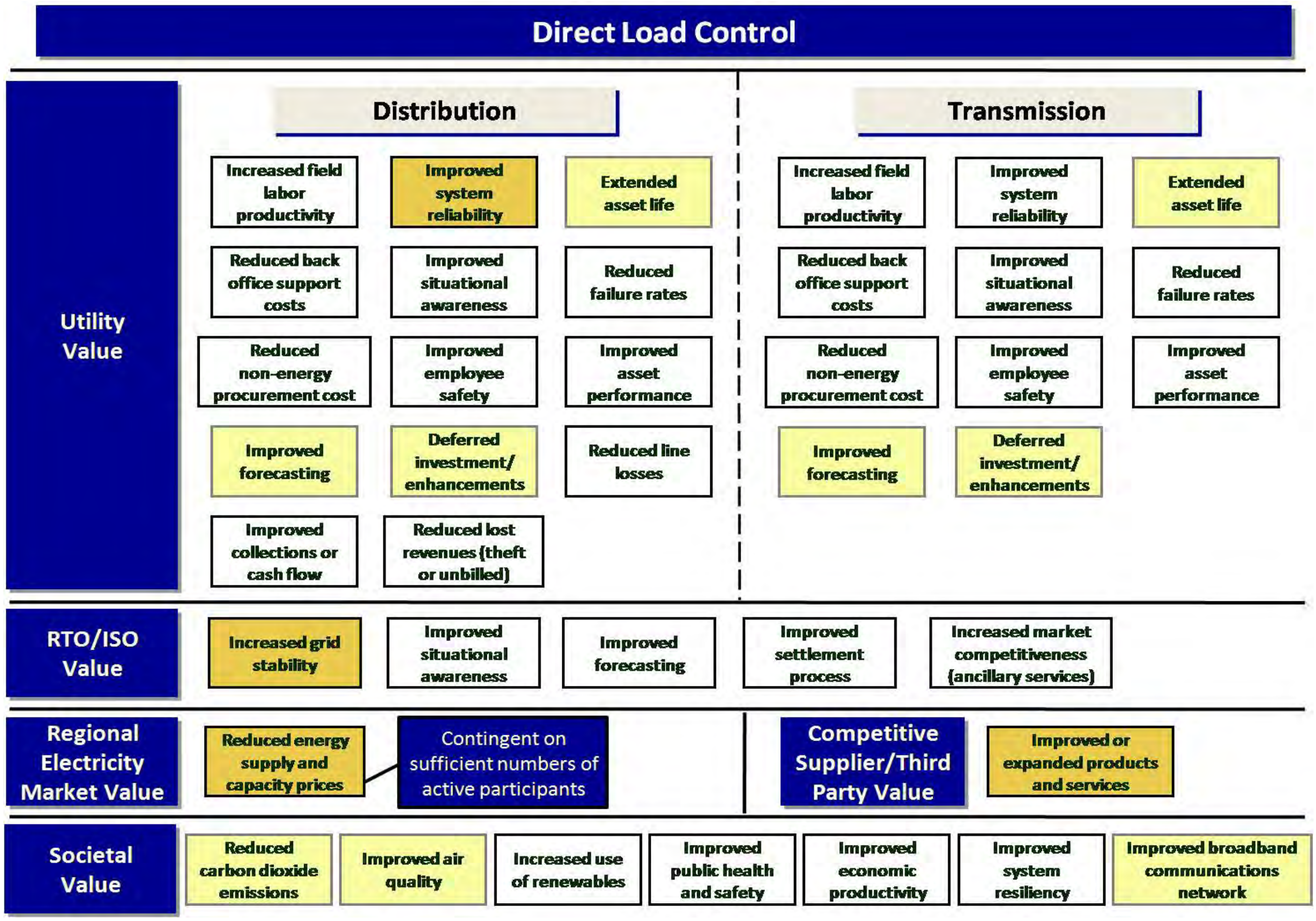
The utility may require a demand response management system to send signals to customers' devices. Additionally, the utility may require customer information system and billing system upgrades. Customers must install in-premises devices for direct load control demand response.

Potential Sources of Benefits and Beneficiaries

Direct Load Control

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)	○		○		○	
	Increased ability to manage energy cost	○		○		○	
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○	○	○
	Improved power quality						

Contingent on sufficient numbers of active participants



The following primary potential benefits have been identified:

- **Utilities**
  - Improved system reliability– The utility has increased control and can call for demand response reductions to improve system conditions
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- if sufficient numbers of customers provide conservation sufficient to modify the system-wide load shape or customer participation leads to a sustained reduction in peak energy demand
- **RTO/ISO**
  - Increased grid stability –the RTO benefits from the utility's operation of direct load control in emergency situations
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Third parties can provide direct load control demand response programs.

Potential secondary sources of benefits include:

- **Customers**
    - Reduced energy usage (conservation) – Customers may use less electricity when under direct load control
    - Increased ability to manage energy costs – This assumes financial benefits exist for participating in a direct load control program and the customer can choose to participate on a per event basis
    - Improved system reliability– Customers benefit from the utility's direct control to improve system stability and prevent outages
- **Utilities**
    - Extended asset lives – if sufficient customers are participating and reducing usage to result in less wear on electric system components
    - Deferred investment/enhancements – if sufficient customers are participating and reducing usage to result in, leading to less need for new equipment
    - Improved forecasting – With direct control and sufficient customer participation, utilities could directly reduce usage to conform to forecasts. This application doesn't directly improve forecasts; however, it allows the utility to reduce the impact of potential error in forecasts
- **Society**
    - Reduced carbon dioxide emissions – energy conservation resulting from this application could result in reduced need for fossil-fueled generation
    - Improved air quality – If sufficient numbers of customers reduce their energy usage and the reduction comes from dirtier generation, air quality can be improved
    - Improved broadband/communications network – This benefit may be achieved if public communications networks are expanded or improved as part of the smart grid system, thereby increasing access or improving functionality.

Potential Negative Impacts

Identified potential negative impacts include: safety or health concerns due to load control of critical customer service, potential damage to customer equipment from increased cycling and potential increases in customer complaints or liability for the utility. These potential negative impacts have been successfully addressed by utilities performing this application by proper program design and policy.

System Frequency Signal to Customer Load Control Devices

Description

Customer devices or appliances equipped with electric system frequency sensors can detect changes in the electric system frequency that indicate instability due to insufficient generation and drop load. Frequency sensing can be added to existing appliances or for very low cost be incorporated into future appliance designs. Customers could provide frequency response load reduction to utilities or third parties in exchange for a financial benefit. The participants in this workgroup recognized that too much uncoordinated load shedding was problematic for this application.

The technology to implement this application is mature but has not been implemented due to cost-benefit limitations and difficulty in providing customers with an incentive to participate. The in-premises communications capabilities that may be developed in other applications could increase the appeal for this application.

Potential Sources of Costs

Customers bear the costs for device and appliance sensors. Additionally, some communication capability may be required by the customer's device or appliance to report participation in a frequency response event. The communication capability could be through the customer's HAN and AMI network. The utility may need to upgrade customer information systems, demand response systems, AMI communications networks and AMI management systems to support this application.

Potential Sources of Benefits and Beneficiaries

System Frequency Signal to Customer Load Control Devices

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○	○	○
	Improved power quality	○	○	○	○	○	○

Contingent on sufficient numbers of active participants

System Frequency Signal to Customer Load Control Devices

Utility Value

Distribution

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements
- Reduced line losses
- Improved collections or cash flow
- Reduced lost revenues (theft or unbilled)

Transmission

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements

RTO/ISO Value

- Increased grid stability
- Improved situational awareness
- Improved forecasting
- Improved settlement process
- Increased market competitiveness (ancillary services)

Regional Electricity Market Value

- Reduced energy supply and capacity prices

Competitive Supplier/Third Party Value

- Improved or expanded products and services

Societal Value

- Reduced carbon dioxide emissions
- Improved air quality
- Increased use of renewables
- Improved public health and safety
- Improved economic productivity
- Improved system resiliency
- Improved broadband communications network

The following primary potential benefits have been identified:

- **RTO/ISO**
  - Increased grid stability – Customers' devices and appliances will automatically decrease their load on the system during a low frequency event, increasing system stability.

Potential secondary sources of benefits include:

- **Customers**
  - Improved system reliability– if sufficient customers are participating and reducing usage to result in improved system reliability
  - Improve power quality – if sufficient customers are participating to maintain system frequency
- **Utilities**
  - Extended asset lives – if sufficient customers are participating and reducing usage to result in less wear on electric system components
  - Improved system reliability – if sufficient customers are participating to result in reduced usage, improving system reliability
- **RTO/ISO**
  - Increased market competitiveness (ancillary services) – This application provides additional sources for frequency based response
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Third parties can aggregate customers for purposes of providing larger amounts of frequency response
- **Society**
  - Improved public health and safety – through reduced outages
  - Improve economic productivity – through reduced outages.

Potential Negative Impacts

Identified potential negative impacts for this application are potential damage to customer equipment from increased cycling and potential increases in customer complaints or liability for the utility.

System Renewables Output to Customers

Description

Customer's displays or devices could receive information about the current output of the electric system's renewable generation. The customer can choose to reduce their energy usage or program devices to use less energy when renewable output is low. Information about the system's renewable output is provided by the Regional Transmission Operator. Increasing usage when renewable output is relatively high (or reducing usage when renewable output is relatively low) does not necessarily increase renewable generation or use of renewable energy, since renewable energy is generally dispatched to its maximum capability when available, i.e. it typically is not "on the margin" for dispatch purposes.

As described this application is not mature, as it relies on still developing in-premises communications technologies and devices.

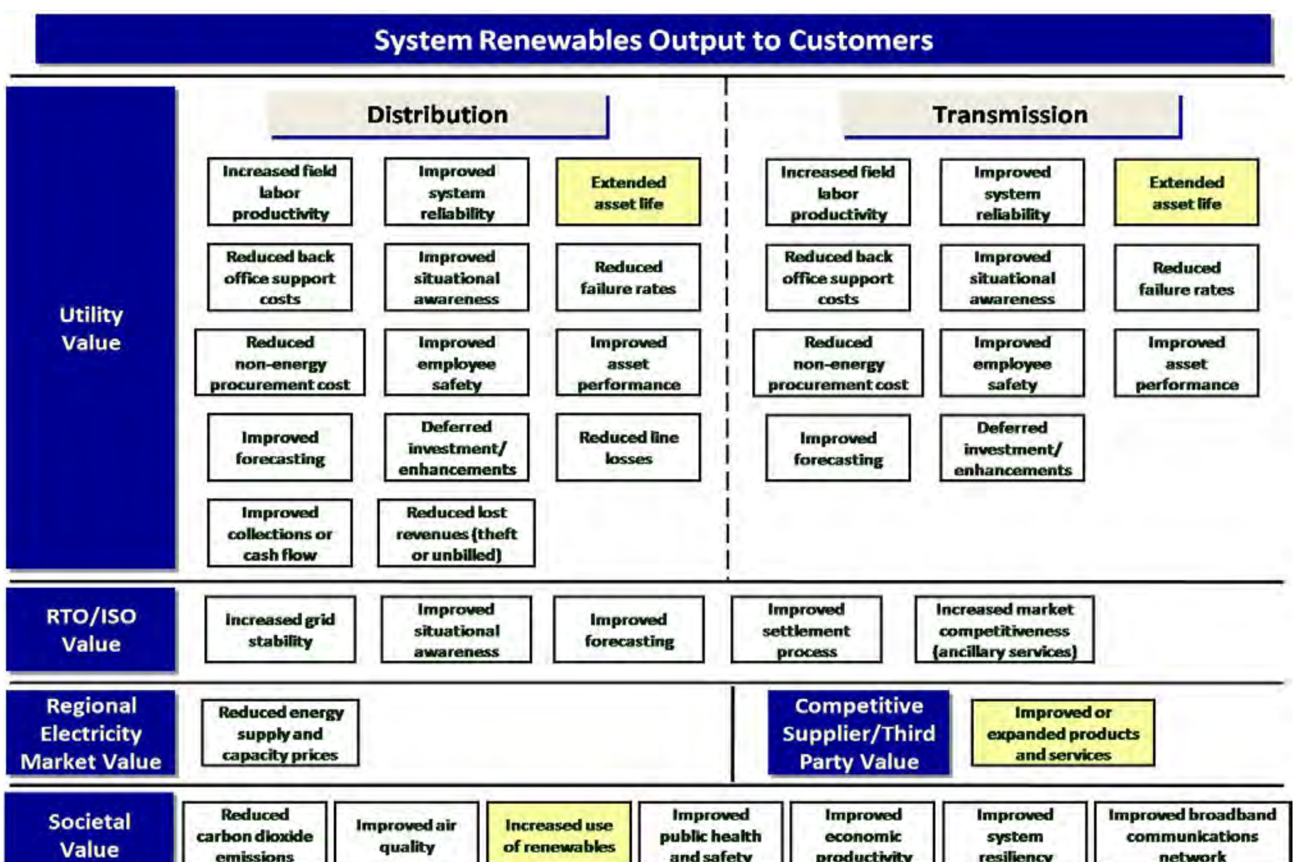
Potential Sources of Costs

The RTO currently provides this data on their web site. Utility system updates may be required to deliver this data to customers' in-premises devices. Customers may require devices which can respond to signals based on renewable output.

Potential Sources of Benefits and Beneficiaries

System Renewables Output to Customers

	Customer Groups	Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)	○		○		○	
	Increased ability to manage energy cost						
	Enhanced services to the customer	○		○		○	
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						



No primary benefits were identified.

The following secondary potential benefits have been identified:

- **Customers**
  - Reduced energy usage (conservation) – Customers who respond to low renewable generation may conserve energy
  - Enhanced services to the customer – Some customers have expressed a desire to have renewable generation output presented to them
- **Utilities**
  - Extended asset lives – if sufficient customers are participating and reducing usage to result in less wear on electric system components
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Third parties may be able to offer services related to low renewable generation signals
- **Society**
  - Increased use of renewables –This application may foster additional public support for investment in renewable generation. If limits on renewable integration are reached, then sufficient customer load tracking the renewable output may allow a higher percentage of renewable generation to be integrated into the electric grid.

Potential Negative Impacts

To the extent load shifting occurs and increases fossil-fueled generation, i.e. shifts usage to periods when fossil fuel units are "on the margin," this has the potential to increase carbon dioxide emissions and, if in sufficient amount, to reduce air quality.

Distribution Automation Applications

The distribution automation applications group includes applications that are typically utility-centric while providing potential benefits to the customer through increased reliability or improved system efficiency.

Distribution Automation Applications include:

- Automatic Circuit Reconfiguration
- Improved Fault Location
- Dynamic System Protection for Two-Way Power Flows and Distributed Resources
- Dynamic Volt-VAR Management
- Conservation Voltage Optimization.

Automatic Circuit Reconfiguration

Description

A smart distribution system can use communicating switches and circuit reclosers to reconfigure the distribution system during an outage. Automatic reconfiguration allows for a portion of customers who would traditionally suffer a distribution level outage to have their power restored in a few seconds. An advanced system provides better information to the utility about the location of faults and the current configuration of the distribution system.

This is a mature application. ComEd is currently deploying some devices envisioned by this application. Additional devices and improved inter-device communications would provide all of the benefits envisioned by the Collaborative.

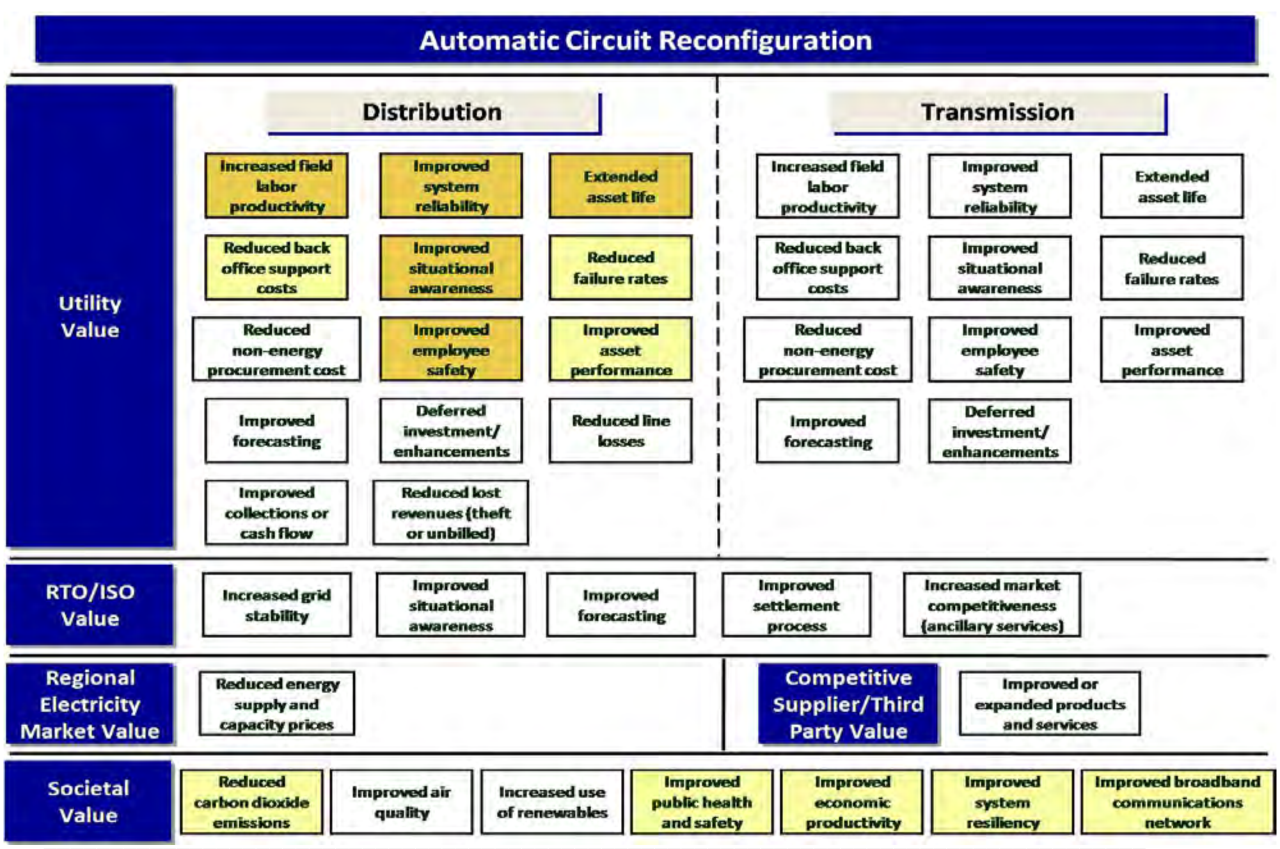
Potential Sources of Costs

The utility will require new or upgraded distribution system switches and reclosers, a communications system suitable for this application which could be, in whole or in part, leased from existing communications providers or built as a new network, depending on what alternatives are most cost-effective, and a new or upgraded distribution management system. The communications network may be part of the AMI network.

Potential Sources of Benefits and Beneficiaries

Automatic Circuit Reconfiguration

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	●	●	●	●		
	Improved power quality	●	●	●	●		



The following primary potential benefits have been identified:

- **Customers**
  - Improved system reliability– During outages, a significant percentage of customers will have a momentary outage and not a prolonged outage
  - Improved power quality – Automated circuit reconfiguration will better coordinate reclosers attempting to clear system faults and decrease fault current exposure to customers' equipment
- **Utilities**
  - Increased field labor productivity – The system will improve the location of system faults and allow utility workers to begin repairs sooner
  - Extended asset life – Automated circuit reconfiguration will better coordinate reclosers attempting to clear system faults and decrease fault current exposure to electric system assets
  - Improved system reliability – During outages, a significant percentage of customers will have a momentary outage and not a prolonged outage
  - Improved employee safety – due to decrease field workers time in the field
  - Improved situational awareness – The automated system provides better information to the utility's distribution management system.

Potential secondary sources of benefits include:

- **Utilities**
  - Reduced back office support costs – Improved information and distribution management reduces back office costs
  - Reduced failure rates –future failures would be less likely
  - Improved asset performance –asset performance would be improved
- **Society**
  - Reduced carbon dioxide emissions – This benefit is likely to be minor and for this application is obtained by the reduction in the utility's use of vehicles by their field workforce
  - Improved public health and safety – Reduced area and duration of outages improves public safety
  - Improved economic productivity – due to reduced area and duration of outages
  - Improved system resiliency (disaster recovery) – due to reduced area and duration of outages
  - Improved broadband/communications network – This benefit may be achieved if public communications networks are expanded or improved in order to support communications to utility devices needed

for this application, thereby increasing access or improving functionality.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Improved Fault Location

Description

Additional sensors with communications can be installed to improve the utility's ability to detect the location of system faults. The fault sensors can report to the utility distribution management system and help pinpoint the location of system faults.

This is a mature technology which has historically not been implemented by utilities due to limited field communications. This application can benefit from AMI or other smart grid communications networks.

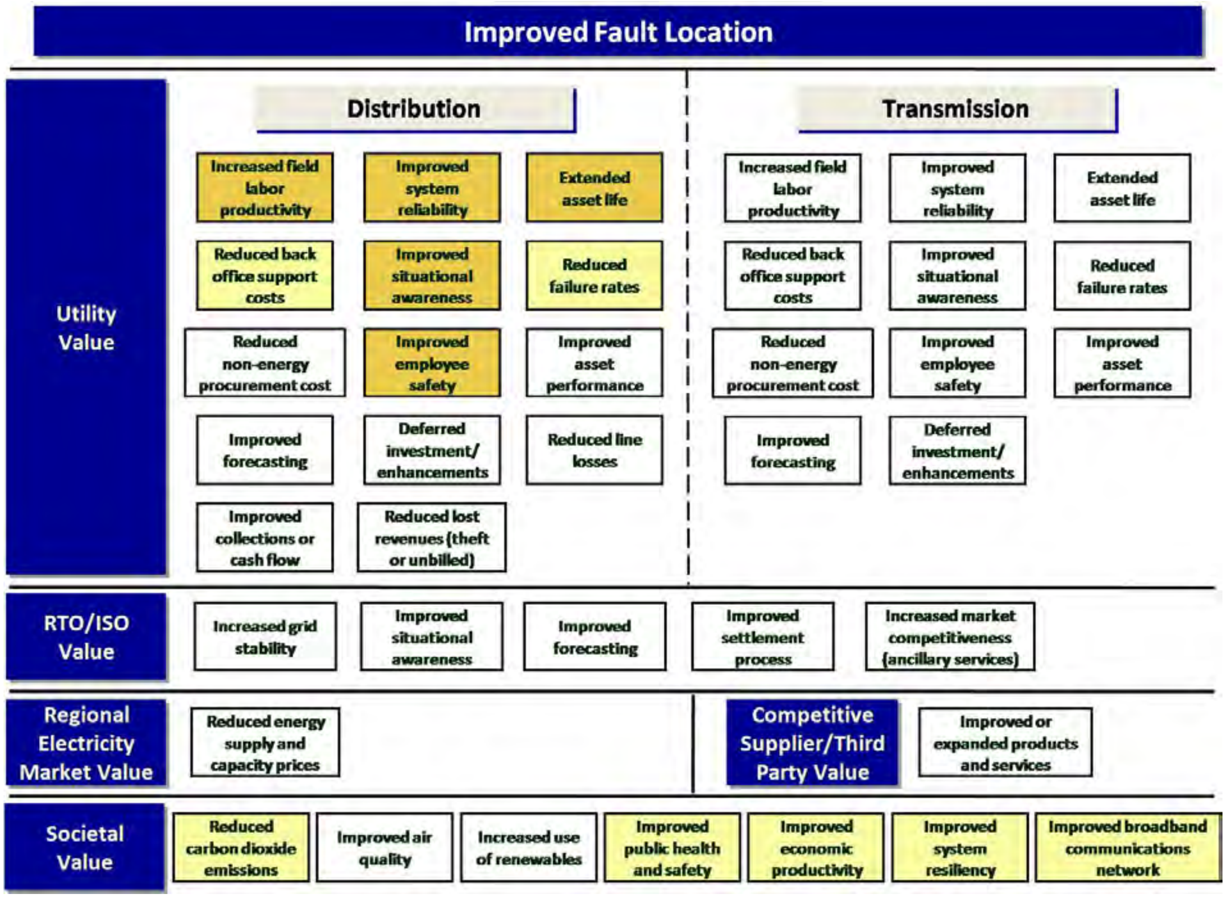
Potential Sources of Costs

The utility will require fault sensors, a field network which may be part of the AMI network, and a new or upgraded distribution management system.

Potential Sources of Benefits and Beneficiaries

Improved Fault Location

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	●	●	●	●		
	Improved power quality						



The following primary potential benefits have been identified:

- **Customers**
  - Improved system reliability – The utility will be able to repair outages more quickly
- **Utilities**
  - Increased field labor productivity – Field workers will spend much less time patrolling lines, searching for outages
  - Extended asset life – By using fault location sensors, utilities can prevent some circuit recloser operations that expose system assets to fault current
  - Improved system reliability – Reducing the duration of outages improves the system reliability and extending asset life improves system reliability
  - Improved employee safety – due to decreased employee time in the field
  - Improved situational awareness – Fault location sensors report back to the distribution management system.

Potential secondary sources of benefits include:

- **Utilities**
  - Reduced back office support costs – Improved information and distribution management reduces back office costs
  - Reduced failure rates – With extend asset lives, equipment failures would be less likely
- **Society**
  - Reduced carbon dioxide emissions – This benefit is likely to be minor and for this application is obtained by the reduction in the utility's use of vehicles by their field workforce
  - Improved public health and safety – due to reduced area and duration of outages
  - Improved economic productivity – due to reduced area and duration of outages
  - Improved system resiliency (disaster recovery) – due to reduced area and duration of outages
  - Improved broadband/communications network – This benefit may be achieved if public communications networks are expanded or improved in order to support communications to utility devices needed for this application, thereby increasing access or improving functionality.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Dynamic System Protection for Two-Way Power Flows and Distributed Resources

Description

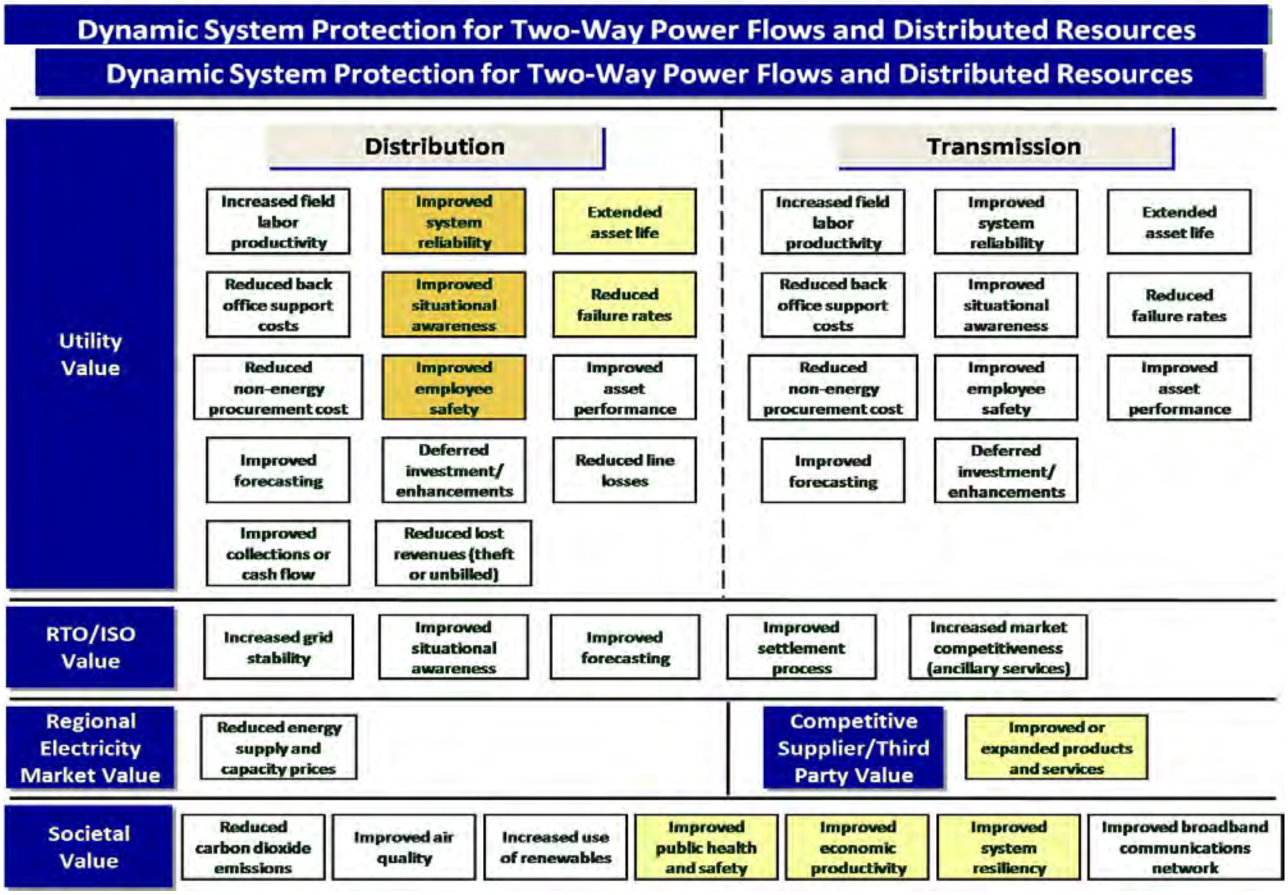
The existing distribution system is designed and built with the assumption that electricity is supplied to customer end points. As distributed resources become more prevalent, the distribution system will require upgrades that provide sensing of local system conditions and systems and devices that send control signals and operational settings to devices to maintain safety and stability.

The underlying technologies for this application are mature, but no products exist for this application because there is no current need until greater numbers of distributed resources are deployed.

Potential Sources of Costs

The utility will need new or upgraded devices that perform system protection and circuit reconfiguration, new or upgraded devices that can sense or communicate with distributed resources and a new or upgraded distribution management system. Customers participating in net generation programs may be required to install communications and control systems for their distributed resources.

Potential Sources of Benefits and Beneficiaries



The following primary potential benefits have been identified:

- **Customers**
  - Facilitated customer generation – Customers can currently use distributed resources and participate in net generation programs. A more dynamic system could increase the value to customers for providing net generation
  - Improved system reliability– assuming that increased net generation can improve system availability for all customers
- **Utilities**
  - Improved system reliability – assuming that increased net generation reduces the impact of system outages
  - Improved employee safety – assuming that improved protection systems that accommodate distributed resources improve field worker safety
  - Improved situational awareness – assuming the existence of additional sensing capability that is communicated to the utility's distribution management system.

Potential secondary sources of benefits include:

- **Customers**
  - Improved power quality – Improved sensing capability can inform customers and the utility of power quality issues that may arise with widespread distributed resources
- **Utilities**
  - Extended asset life – Monitoring and measuring conditions of a system with widespread distributed resources allows the utility to operate the distribution system in a manner that reduces stress on system assets
  - Reduced failure rates – Monitoring and measuring conditions of a system with widespread distributed resources allows the utility to operate the distribution system in a manner that reduces stress on system assets
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Third parties may have increased service opportunities if distributed resources are more widely deployed
- **Society**
  - Improved public health and safety – assuming that this application improves system reliability

- Improved economic productivity – assuming that this application improves system reliability
- Improved system resiliency (disaster recovery) – assuming that distributed resources can be used to recover more quickly from outages.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Dynamic Volt-VAR Management

Description

The smart distribution system can monitor voltage and power quality at multiple points throughout the system and communicate control signals to capacitor banks to optimize system operation. This application would include the use of voltage and power quality monitoring devices along with capacitor bank and load tap changing transformer controls to control the voltage and reactive power on the system for reliability. While AMI meters would likely be used to provide voltage measurements at points throughout the distribution system, an AMI system is not required for this application and voltage measurements can be provided by devices installed specifically for this application.

The fundamental capabilities of this application rely on mature technologies. The application as described is in the developmental stage as utilities implement and integrate AMI meters, field communications networks, and capacitor and transformer controls into a working system.

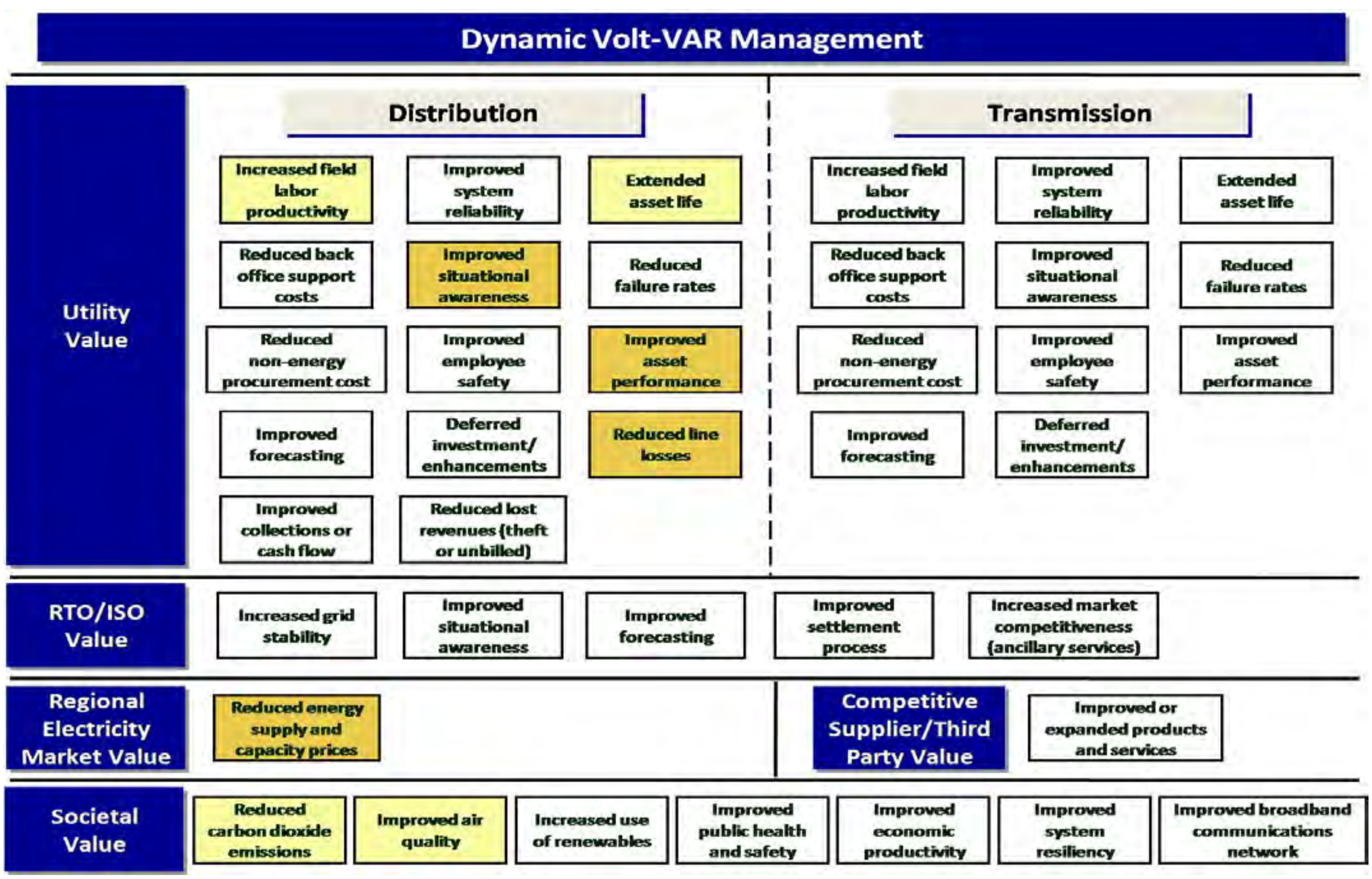
Potential Sources of Cost

The utility will require new or upgraded capacitor bank controls, transformer controls, field communications (which may be provided by an AMI system), and a new or upgraded distribution management system.

Potential Sources of Benefits and Beneficiaries

Dynamic Volt-VAR Management

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality	●	●	●	●		



The following primary potential benefits have been identified:

- **Customers**
  - Improved power quality – Customers can benefit from improved voltage and VAR control
- **Utilities**
  - Reduced line losses – Utilities can use this application to improve power factor, reducing line losses
  - Improved asset performance – Utilities can manage voltage and power quality to improve asset performance
  - Improved situational awareness – This application provides improved information to the utility's distribution management system
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- Reduced line losses and improved power factor can decrease the amount of energy purchased and result in a lower market price for all customers or decrease the amount of capacity needed to serve peak loads.

Potential secondary sources of benefits include:

- **Utilities**
  - Increased field labor productivity – if existing manual capacitor bank operations are replaced with automation
  - Extended asset lives – Asset lives can be extended by operating the distribution system with a finer degree of control
- **Society**
  - Reduced carbon dioxide emissions – if reduced line losses decrease the need for fossil-fueled generation
  - Improved air quality – if reduced line losses decrease the amount of electricity generation.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Conservation Voltage Optimization

Description

This application is an extension of *Dynamic Volt-VAR Management.* The smart distribution system can sense and control the voltage level more capably. Utilities can maintain a lower regulated voltage providing savings to the customer and increasing system efficiency. This application would include the use of voltage and power quality monitoring devices along with capacitor bank and Load Tap Changing transformer controls to control the voltage and reactive power on the system for conservation optimization. This application could be used in a near real time manner to reduce usage during periods of high energy costs or to alleviate system congestion.

As with *Dynamic Volt-VAR Management*, this application is based on mature technologies that have not been implemented in this fashion due to the lack of a wide set of sensor devices and a field network. This application envisions using AMI meters and the AMI or smart grid network to enable this application.

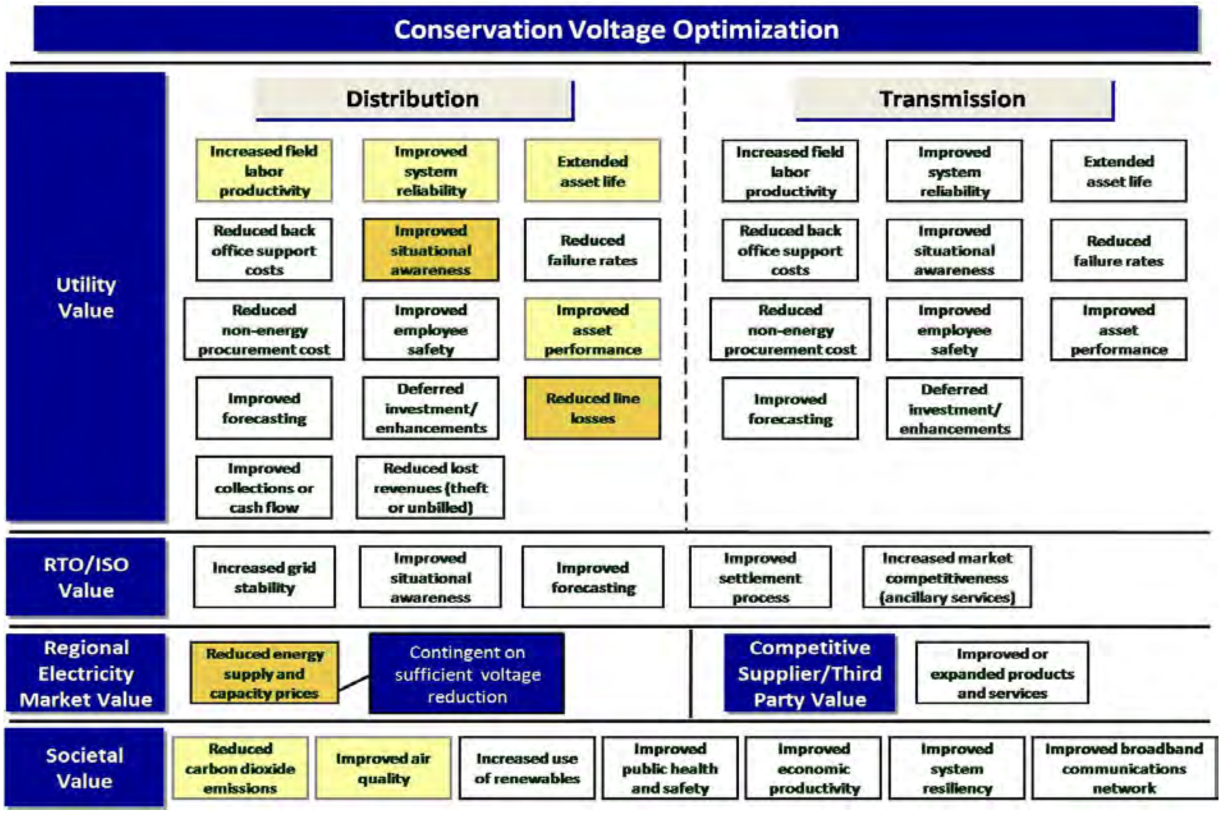
Potential Sources of Costs

The utility will require new or upgraded capacitor bank controls, transformer controls, field communications (which may be provided by an AMI system), and a new or upgraded distribution management system.

Potential Sources of Benefits and Beneficiaries

Conservation Voltage Optimization

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)	●	●	●	●		
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						



The following primary potential benefits have been identified:

- **Customers**
  - Reduced energy usage (conservation) – Customers operating at a lower voltage use less energy
- **Utilities**
  - Reduced line losses – Decreased voltage can reduce the line losses
  - Improved situational awareness – Better information is provided to the utility's distribution management system
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- If a sufficient reduction occurs by better managing the voltage, energy market prices may fall, benefitting all customers.

Potential secondary sources of benefits include:

- **Utilities**
  - Increase field labor productivity – assuming that the asset performance and asset life extension benefits reduce field labor for asset repairs and replacement
  - Extended asset life – Asset life can be extended by operating the distribution system with a finer degree of control

- Improved system reliability – assuming that voltage reduction can be used to reduce the load on system components that may be overloaded and thereby prevent outages
- Improved asset performance – Utilities can manage voltage to improve asset performance

- **Society**
  - Reduced carbon dioxide emissions – if energy savings from voltage reduction are sufficient to decrease output from fossil-fueled generators
  - Improved air quality – if energy savings from voltage reduction are sufficient to decrease generation output.

Potential Negative Impacts

The potential negative impact for this application is a concern for potential customer equipment damage or poor performance due to voltage levels at the low end of the utility delivered range.

System and Asset Monitoring and Modeling

The system and asset monitoring and modeling applications group is related to the distribution automation group and is differentiated by the timing of the activities. The distribution automation applications occur in real time and the system and asset monitoring and modeling applications are performed in a more analytical manner. As with the distribution automation group, these applications can leverage AMI meter data and the AMI communications network.

System and Asset Monitoring and Modeling Applications include:

- Enhanced System Modeling and Planning
- Asset Sizing Optimization
- Asset Condition Monitoring.

Enhanced System Modeling and Planning

Description

Data from AMI meters and distribution system sensors provide the utility an increased ability to validate system models and efficiently plan for system upgrades. When sufficient numbers of sensors are in place and data are available, some traditional models can be updated with true representations of the system.

Modeling and planning are mature applications that benefit from the increase in data. New models and systems may be developed to take full advantage of the available data.

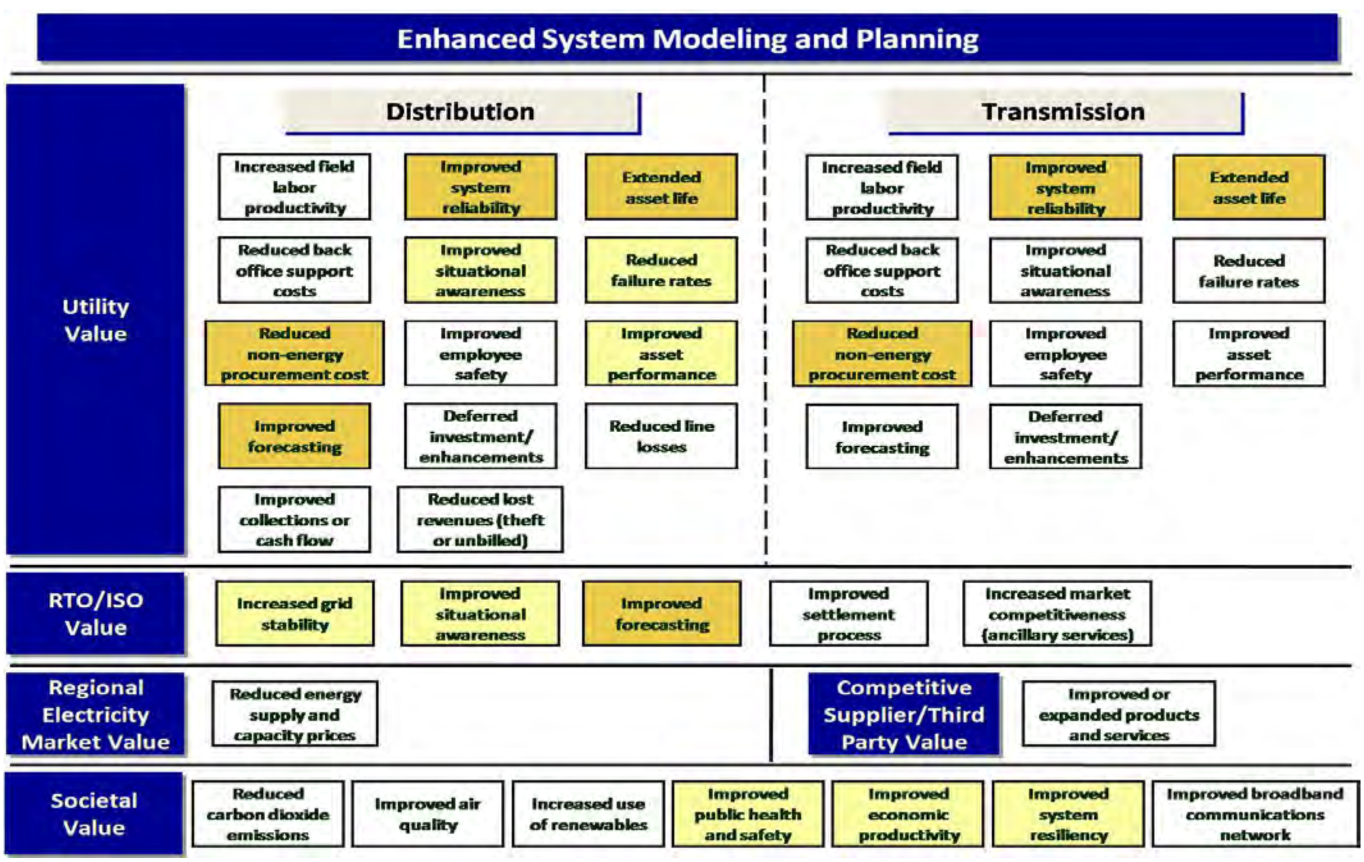
Potential Sources of Costs

The utility can take advantage of AMI meters or other smart grid devices to provide data. The utility may require new or upgraded electric system modeling and planning systems.

Potential Sources of Benefits and Beneficiaries

Enhanced System Modeling and Planning

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○	○	○
	Improved power quality						



The following primary potential benefits have been identified:

- **Utilities**
  - Extended asset life – This benefit assumes that improved modeling and planning enhance the utility's ability to correctly size assets and operate them within design parameters
  - Improved system reliability – Improved modeling and planning may decrease the number of outages that occur
  - Improved forecasting – Improved modeling and planning benefits short and long term forecasting
  - Reduced non-energy procurement cost – Improved planning reduces high cost procurement needs
- **RTO/ISO**
  - Improved forecasting – Improved modeling and planning benefits short and long term forecasting.

Potential secondary sources of benefits include:

- **Customers**
  - Improved system reliability – Improved modeling and planning may decrease the number of outages
- **Utilities**
  - Reduced failure rates – This benefit assumes that improved modeling and planning enhance the utility's ability to correctly size assets and operate them within design parameters
  - Improved asset performance – This benefit assumes that improved modeling and planning enhance the utility's ability to correctly size assets and operate them within design parameters
  - Improved situational awareness – Improved models that correlate well with measured data can improve a utility's situational awareness
- **RTO/ISO**
  - Increased grid stability – This benefit assumes that improved modeling and planning enhance the utility's ability to correctly size assets and operate them within design parameters
  - Improve situational awareness – Improved models that correlate well with measured data can improve a utility's situational awareness
- **Society**
  - Improved public health and safety – Reduced equipment failure rates results in fewer outages
  - Improve economic productivity – Reduced equipment failure rates results in fewer outages
  - Improve system resiliency (disaster recovery) – Improved system models and planning can improve system recovery time.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Asset Sizing Optimization

Description

Data provided by AMI meters and new distribution system devices connected by the smart grid network provide the utility with the ability to accurately determine loading and view operational attributes of distribution system components. The increase in system visibility allows the utility to correctly size system components and replace them based on actual operating conditions. This application is used operationally in a more focused manner than the above long term System Modeling and Planning application.

This application is mature and only depends on a sufficient quantity and quality of data to implement. Ameren has used data provided by their fixed network AMR system to perform this application.

Potential Sources of Costs

The utility will require new or enhanced distribution management and asset management systems.

Potential Sources of Benefits and Beneficiaries

Asset Sizing Optimization

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○		
	Improved power quality						

Asset Sizing Optimization

Utility Value

Distribution

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements
- Reduced line losses
- Improved collections or cash flow
- Reduced lost revenues (theft or unbilled)

Transmission

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements

RTO/ISO Value

- Increased grid stability
- Improved situational awareness
- Improved forecasting
- Improved settlement process
- Increased market competitiveness (ancillary services)

Regional Electricity Market Value

- Reduced energy supply and capacity prices

Competitive Supplier/Third Party Value

- Improved or expanded products and services

Societal Value

- Reduced carbon dioxide emissions
- Improved air quality
- Increased use of renewables
- Improved public health and safety
- Improved economic productivity
- Improved system resiliency
- Improved broadband communications network

The following primary potential benefits have been identified:

- **Utilities**
  - Extended asset life – Asset life can be extended if utility operators have improved information about system loading conditions and have installed correctly sized equipment
  - Reduced failure rates – Correctly sized equipment will be less likely to fail
  - Improved asset performance – Proper asset sizing allows for more efficient use of utility investment
  - Reduced non-energy procurement cost – Procurement costs can be reduced by deploying correctly sized assets and not oversized equipment.

Potential secondary sources of benefits include:

- **Customers**
  - Improved system reliability– Customers will experience improved system reliability if the utility reduces asset failure rates
- **Utilities**
  - Increased field labor productivity – Reduced equipment failure rates reduces unplanned field labor
  - Improved system reliability – Reduced equipment failure rates improves system reliability
  - Improved employee safety – Reduced equipment failures and asset replacements increases field employees' safety
  - Improve situational awareness – The utility benefits from improved device data
- **Society**
  - Improved public health and safety – Reduced equipment failure rates results in fewer outages
  - Improved economic productivity – due to fewer outages.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Asset Condition Monitoring

Description

Distribution and transmission system sensors allow the utility to monitor the real time performance and health of system components. The utility can take corrective action at the appropriate time, increasing system reliability and operational efficiency.

This is a mature application which has been typically deployed in limited instances due to a lack of field communications.

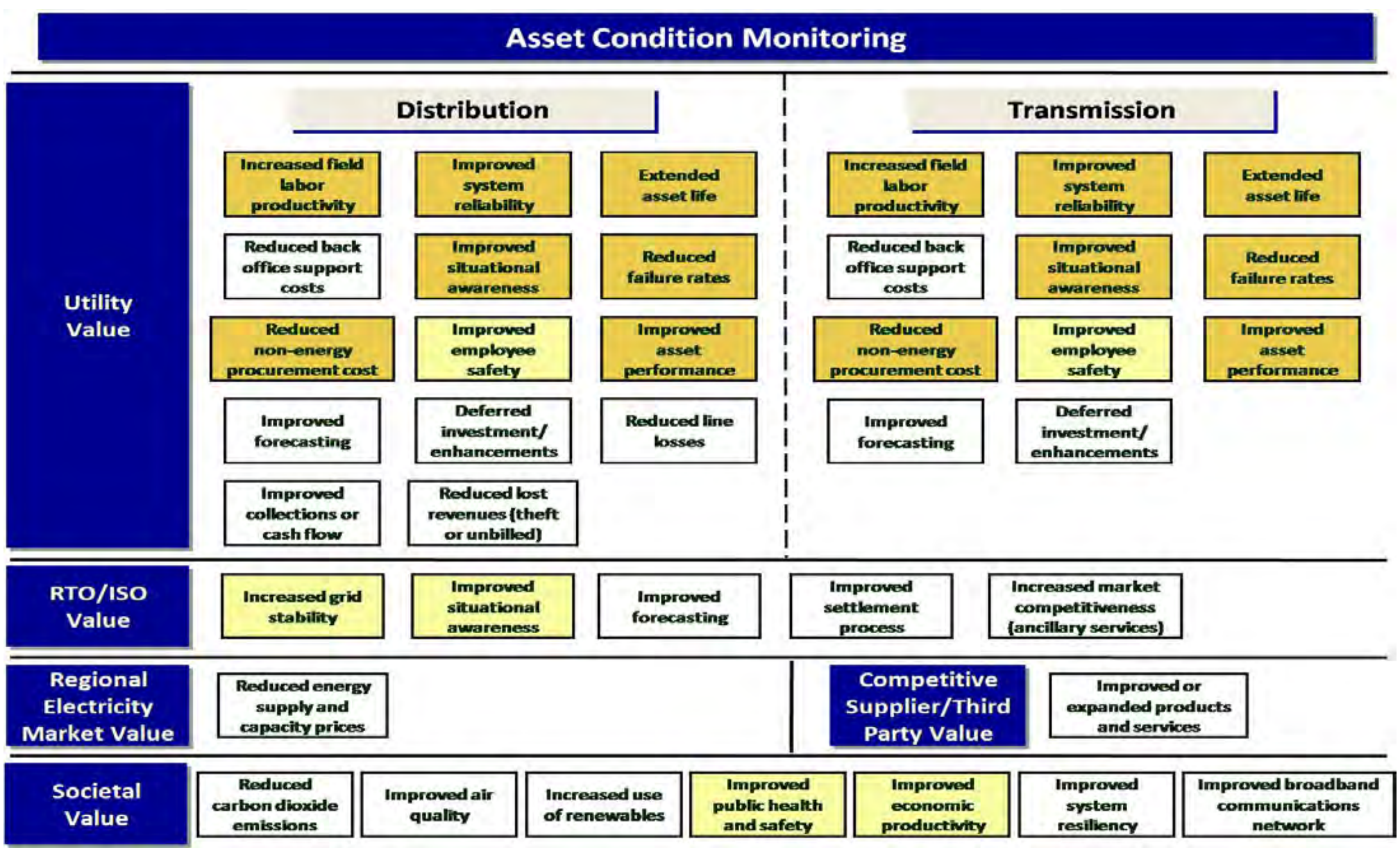
Potential Sources of Costs

The utility will require new or enhanced distribution management and asset management systems. The utility will also require condition monitoring sensors to be added to existing utility equipment or for new equipment to be equipped with conditioning monitoring capabilities.

Potential Sources of Benefits and Beneficiaries

Asset Condition Monitoring

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	●	●	●	●	●	●
	Improved power quality						



The following primary potential benefits have been identified:

- **Customers**
  - Improved system reliability– Customers will experience improved system reliability if the utility reduces asset failure rates

- **Utilities**
  - Increased field labor productivity – Utilities can optimize maintenance and repair activities if they have greater data about asset condition
  - Extended asset life – Asset life can be extended if utility operators have improved information about system loading conditions
  - Reduced failure rates – Improved information about asset loading allows the utility to control the system in a manner that prevents asset failures
  - Improved system reliability– Reduced asset failures improve system reliability
  - Improve asset performance – Better information allows for asset performance optimization
  - Improved situational awareness – System sensors could provide near real time asset condition monitoring, improving situational awareness
  - Reduced non-energy procurement cost – Procurement costs can be reduced by extending asset life and performing planned, as opposed to emergency, asset replacement.

Potential secondary sources of benefits include:

- **Utilities**
  - Improved employee safety – due to reduced equipment failures and asset replacements
- **RTO/ISO**
  - Increased grid stability – Improved condition monitoring of transmission level assets improves grid stability for the RTO
  - Improved situational awareness – Improved condition monitoring of transmission level assets in near real-time can improve situational awareness
- **Society**
  - Improved public health and safety – Reduced equipment failure rates results in fewer outages
  - Improved economic productivity – due to fewer outages.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Distributed Resources Applications

The distributed resource applications group focuses on customer owned generation or storage and better integration of electric vehicles. The first two applications relate to customer owned generation and storage and primarily focus on smaller resources. The second application recognizes the importance of integrating larger resources but provides a high level view of how the integration should occur. The electric vehicle (EV) applications assume that electric vehicles will be increasingly used and detail how the smart grid could incorporate large numbers of EV in the future.

Distributed Resource Applications include:

- Customer Distributed Resource Interconnection
- Coordinated Management of Distributed Resources
- Electric Vehicles: Optimized Charging
- Dispatch of Electric Vehicle Storage.

Customer Distributed Resource Interconnection

Description

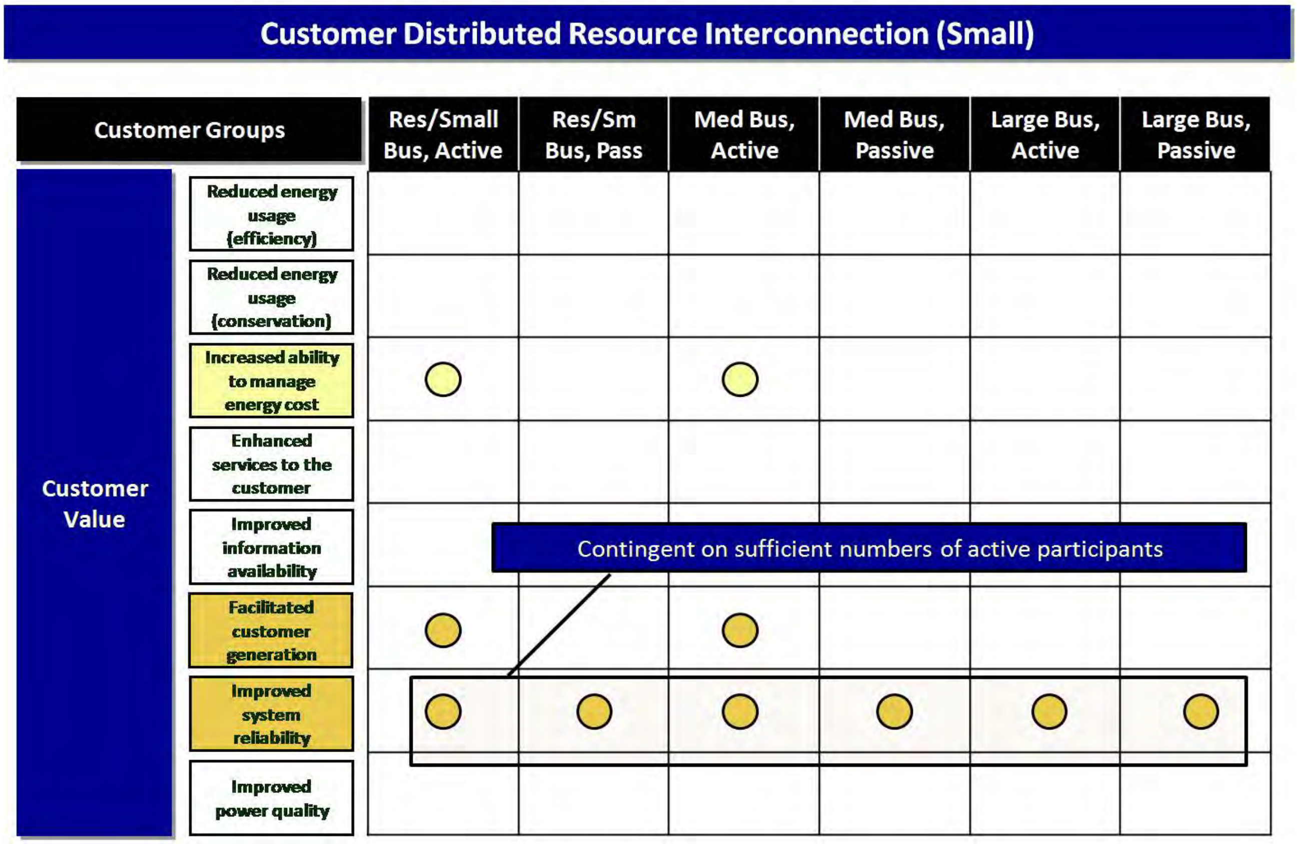
Customer owned generation resources can provide power into the distribution system and help defer construction of new generation or increase the use of renewable energy. The smart grid can facilitate the interconnection of customer generation and storage by providing technical support and through the implementation of other applications that induce the installation of distributed resources. Customer owned generation and storage is possible today, but AMI and other smart grid applications could allow customers to better utilize their own generation and storage and potentially to provide power back to the electric system.

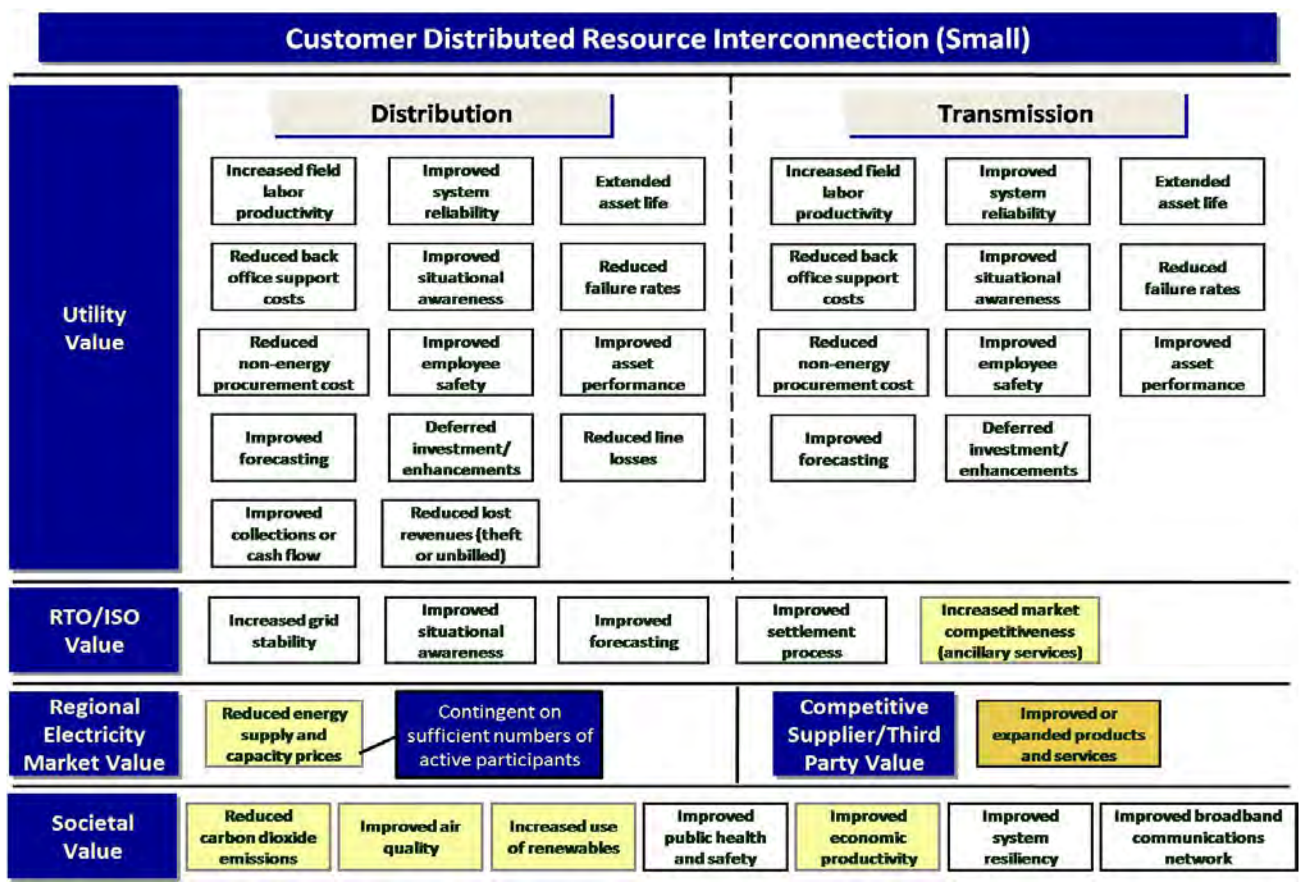
Customer owned distributed resources are currently used by some customer groups under existing technologies. This application is focused on using other smart grid applications to increase the deployment of distributed resources.

Potential Sources of Costs

The utility would require an AMI metering system and potential upgrades to a distribution management system. Customers would pay for their generation or storage devices and installation.

Potential Sources of Benefits and Beneficiaries





The following primary potential benefits have been identified:

- **Customers**
  - Facilitated customer generation and storage – Customers could better determine the economic case for installing and operating distributed resources, especially if time varying electric rates are implemented
  - Improved system reliability– Customers with some types of generation and storage are better protected against outages
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Third parties could develop aggregated distributed resource offerings into the electric market or provide remote equipment monitoring and maintenance.

Potential secondary sources of benefits include:

- **Customers**
  - Increased ability to manage energy cost – Customers could use generation or stored energy during times of high prices or provide energy into the grid
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- if sufficient numbers of customers provide conservation sufficient to modify the system-wide load shape or leads to a sustained reduction in peak energy demand
- **RTO/ISO**
  - Increased market competitiveness (ancillary services) – Customers could be induced to use their generation at the direction of the RTO
- **Society**
  - Increased use of renewables – Some rate and market structures could induce customers to install solar or wind power
  - Reduced carbon dioxide emissions – If larger numbers of renewable generation sources are installed, fossil-fueled generation output could be reduced
  - Improved air quality – if distributed resources are primarily solar, wind or fuel cell based
  - Improved economic productivity – Increased numbers of distributed resources could reduce the impact of system outages.

Potential Negative Impacts

Potential negative impacts for this application are associated with the challenges to existing utility system protection schemes if distributed generation is more widely used. This concern is addressed by the application, *Dynamic System Protection for Two-Way Power Flows and Distributed Resources*. There could be situations in which utility crews or first responders are potentially exposed to energized wires connected to energy storage units or local generation such as photovoltaic solar panels.

Coordinated Management of Distributed Resources

Description

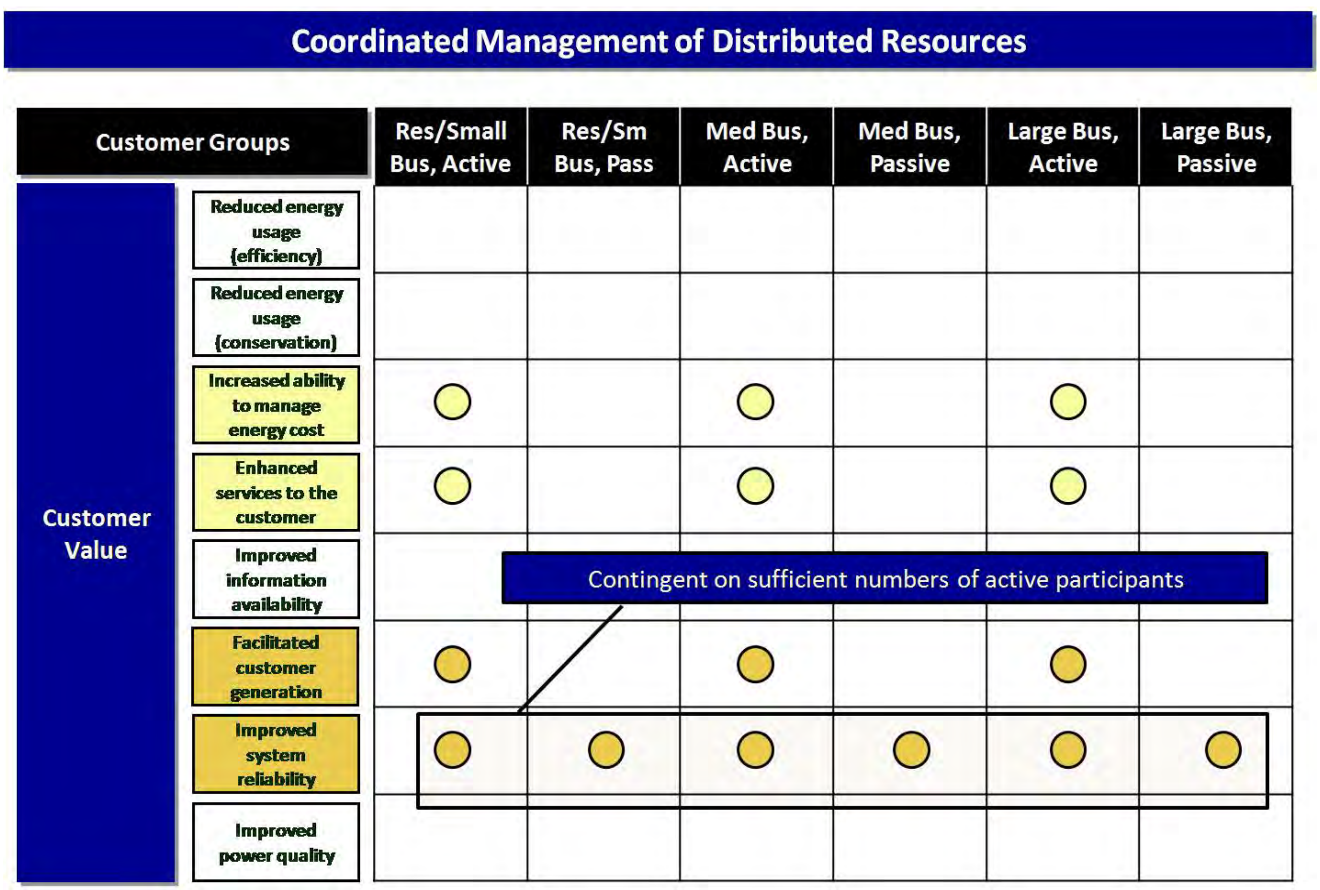
Permitting the utility to communicate with customer owned generation can allow the utility to better manage the distribution system. A utility system that is aware of the operating condition and output of distributed resources can provide better system protection and reliability. This application envisions a scenario where utilities or third parties enroll customers with distributed resources in a voluntary program that allows the utility or third party to operate the customers' generation based on market conditions or for purposes of reliability. This application includes both small and large scale generation and storage devices.

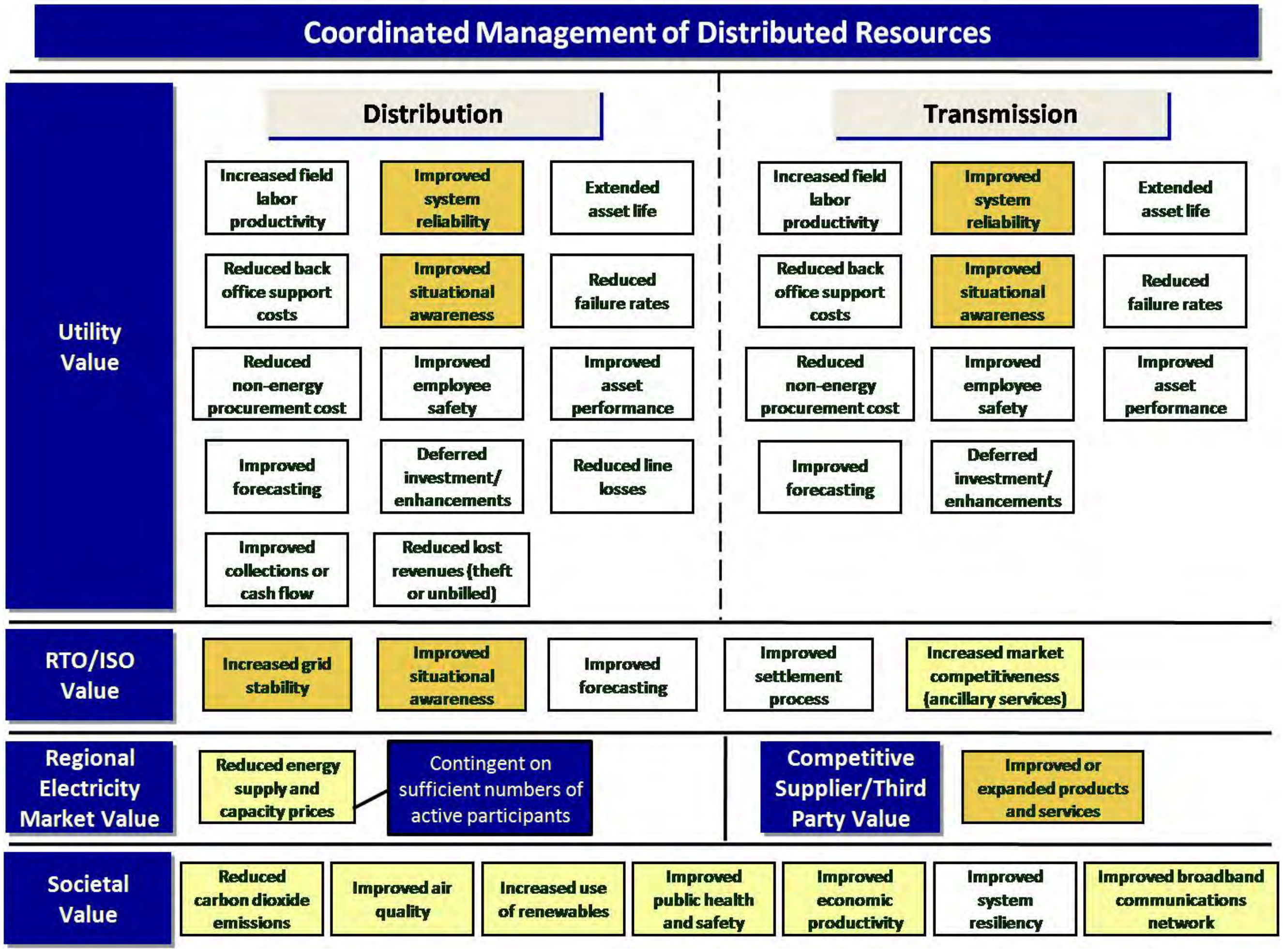
This application depends on the further development of standards for in-premises communications and devices to allow customer owned generation and storage to be remotely monitored and controlled.

Potential Sources of Costs

The utility would require an AMI metering system and upgrades to a distribution management system. Customers would pay for their generation or storage devices and installation.

Potential Sources of Benefits and Beneficiaries





The following primary potential benefits have been identified:

- **Customers**
  - Facilitated customer generation – Customers could see an improved economic case for installing and operating distributed resources
  - Improved system reliability– Customers with some types of generation and storage would be better protected against outages
- **Utilities**
  - Improved system reliability – Utilities could manage distributed resources to improve system reliability
  - Improved situational awareness – Utilities would have information about the operational status and availability of distributed resources
- **RTO/ISO**
  - Increased grid stability – Coordinated management of large and small distributed resources could improve stability
  - Improved situational awareness – The RTO would have information about the operational status and availability of distributed resources
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – Third parties could aggregate distributed resource offerings to participate in the electric

market and/or provide remote equipment monitoring and maintenance.

Potential secondary sources of benefits include:

- **Customers**
  - Increased ability to manage energy costs – Customers could use generation or stored energy during times of high prices or provide energy into the grid
  - Enhanced services to the customer – Customers could be informed about the reliability and status of their distributed resource
- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- With sufficient distributed resources available, energy prices could fall, benefiting all customers
- **RTO/ISO**
  - Increased market competitiveness (ancillary services) – Customers could be induced to use their generation at the direction of the RTO
- **Society**
  - Increased use of renewables – Some rate and market structures could induce customers to install solar or wind power
  - Reduced carbon dioxide emissions – If larger numbers of renewable generation sources are installed, fossil-fueled generation output could be reduced
  - Improve air quality – If sufficient numbers of customers reduce their energy usage and the reduction comes from dirtier generation, air quality can be improved
  - Improved public health and safety – if significant numbers of distributed resources can be managed to reduce the impact of outages
  - Improved economic productivity – Increased numbers of distributed resources could reduce the impact of system outages
  - Improved broadband/communications network – This benefit may be achieved if public communications networks are expanded or improved in order to support communications to customer generation, thereby increasing access or improving functionality.

Potential Negative Impacts

Potential negative impacts for this application relate to the challenges to existing utility system protection schemes if distributed generation is more widely used. This concern is addressed by the application, *Dynamic System Protection for Two-Way Power Flows and Distributed Resources*. There could be situations in which utility crews or first responders are potentially exposed to energized wires connected to energy storage units or local generation such as photovoltaic solar panels.

Electric Vehicles: Optimized Charging

Description

Electric vehicles are not widely available now and their future penetration into the consumer market is unknown. High market penetration of electric vehicles, however, would add significant load to the system which could be managed through the use of smart charging systems. Also, dense localized deployment of electric vehicles and charging stations may strain local distribution system devices.

This application's definition of optimization is intentionally generic. Factors that could be optimized include: local reliability, customer cost, electric system demand and use of renewable resources. A limiting aspect for any of the optimization functions is the customer's need to ensure that their vehicle is adequately charged.

This application is in its infancy and requires the development of standards for vehicle charging and communications and in-premises communications. Additional challenges surround the issue of how to address public charging.

Potential Sources of Costs

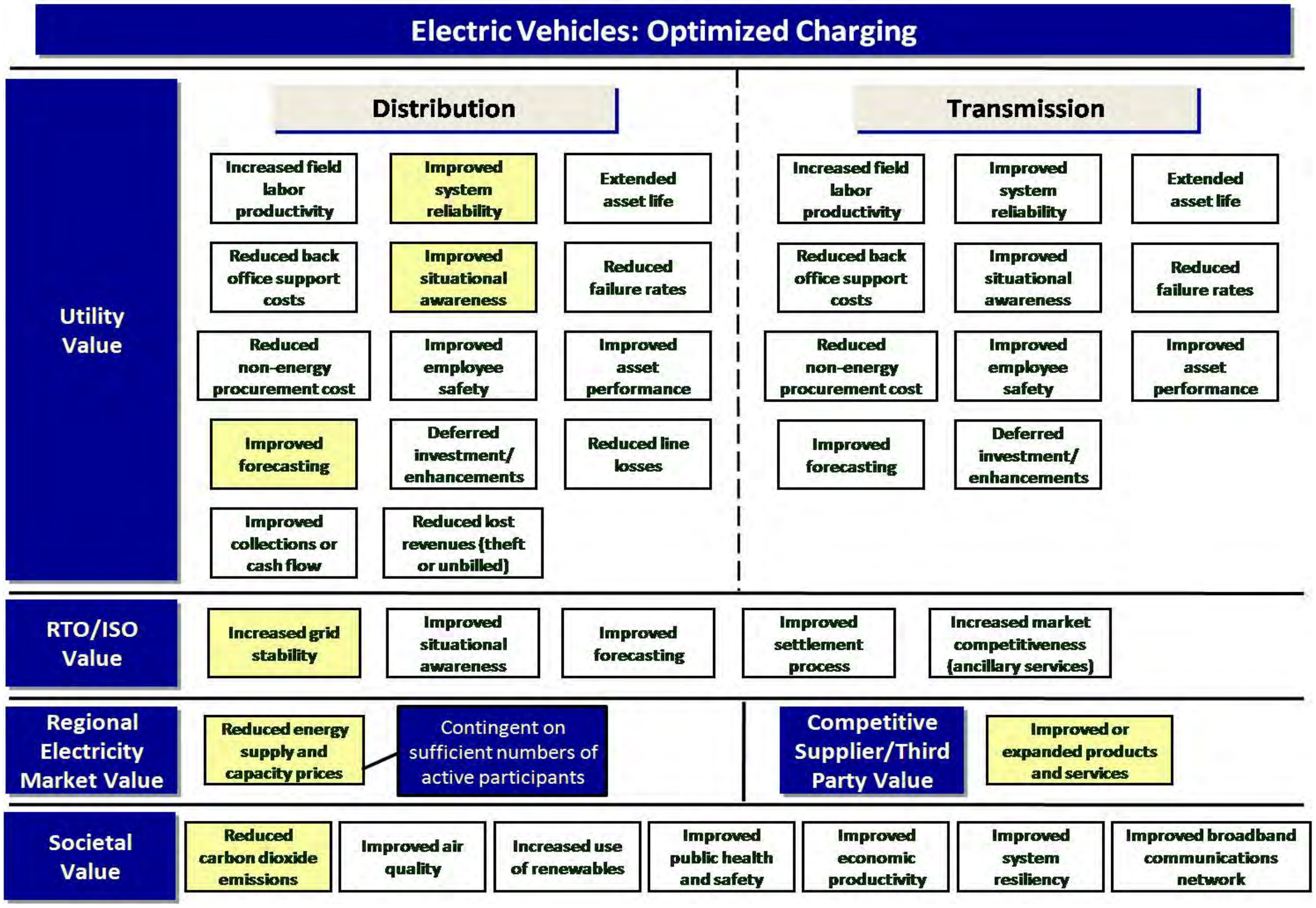
To optimize charging, a communications system and a charging management system are required. Customers also would require a communicating vehicle charging portal which could be part of the car or a separate device.

Potential Sources of Benefits and Beneficiaries

Electric Vehicles: Optimized Charging

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost	○		○		○	
	Enhanced services to the customer	○		○		○	
	Improved information availability	○		○		○	
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality	○	○	○	○		

Contingent on sufficient numbers of active participants



The following primary potential benefits have been identified:

- **Customers**
  - Enhanced services to the customer – Customers could see improved charging and higher charging availability with a well managed system.

Potential secondary sources of benefits include:

- **Customers**
  - Increased ability to manage energy cost – Customers could better take advantage of time based energy rates to charge EVs during periods of low cost
  - Improved information availability – Customers could provide charging preferences and receive feedback
  - Improved power quality – Optimized charging could eliminate localized voltage sags by spreading out charging cycles
- **Utilities**
  - Improved system reliability – Optimized charging could reduce overloading on distribution system devices
  - Improved forecasting – An optimized charging system would provide better data about charging behavior

- Improved situational awareness – An optimized charging system could report real time charging conditions

- **Regional Electricity Market**
  - Reduced energy supply and capacity prices - Optimized charging could result in lower than otherwise system peaks
- **RTO/ISO**
  - Increased grid stability – An optimized charging system could signal an on demand reduction of charging to improve grid stability
- **Competitive Suppliers and Third Parties**
  - Improved/expanded products and services – With time varying rates or incentives for electric vehicles, third parties and customers may find mutually beneficial service opportunities
- **Societal**
  - Reduced carbon dioxide emissions – To the extent that charging optimization results in less use of high carbon fuels and higher use of renewable generation.

Potential Negative Impacts

A potential negative impact is the potential use of base load coal generation for vehicle charging. It is not clear that this issue is associated with this application or if it is a more general aspect of electric vehicle charging. To the extent load shifting occurs and increases fossil-fueled generation (i.e. shifts usage to periods when fossil fuel units are "on the margin"), this has the potential to increase carbon dioxide emissions and, if in sufficient amount, to reduce air quality.

Dispatch of Electric Vehicle Storage

Description

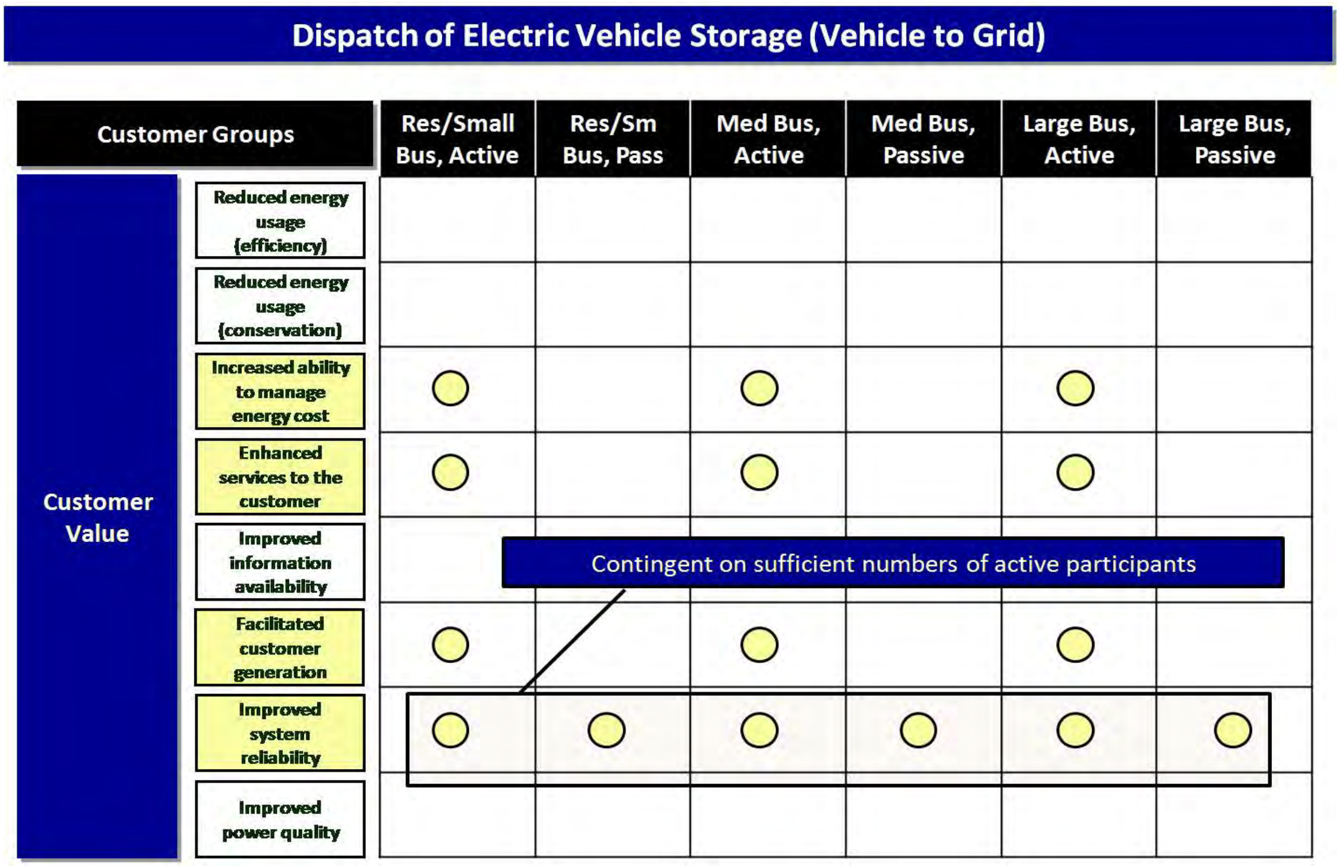
Electric vehicles are not widely available now and their future penetration into the consumer market is unknown. A potential application of electric vehicles is to allow them to provide stored energy as a backup resource when system and market conditions are appropriate. Vehicle-to-grid (V2G) dispatch may have a difficult economic case using available technology based on the increased wear on a vehicle's battery from a greater number of charge/discharge cycles. In addition, V2G would be subject to trade-off evaluation by customers choosing between maintaining vehicle charge levels and obtaining market value for the stored electricity.

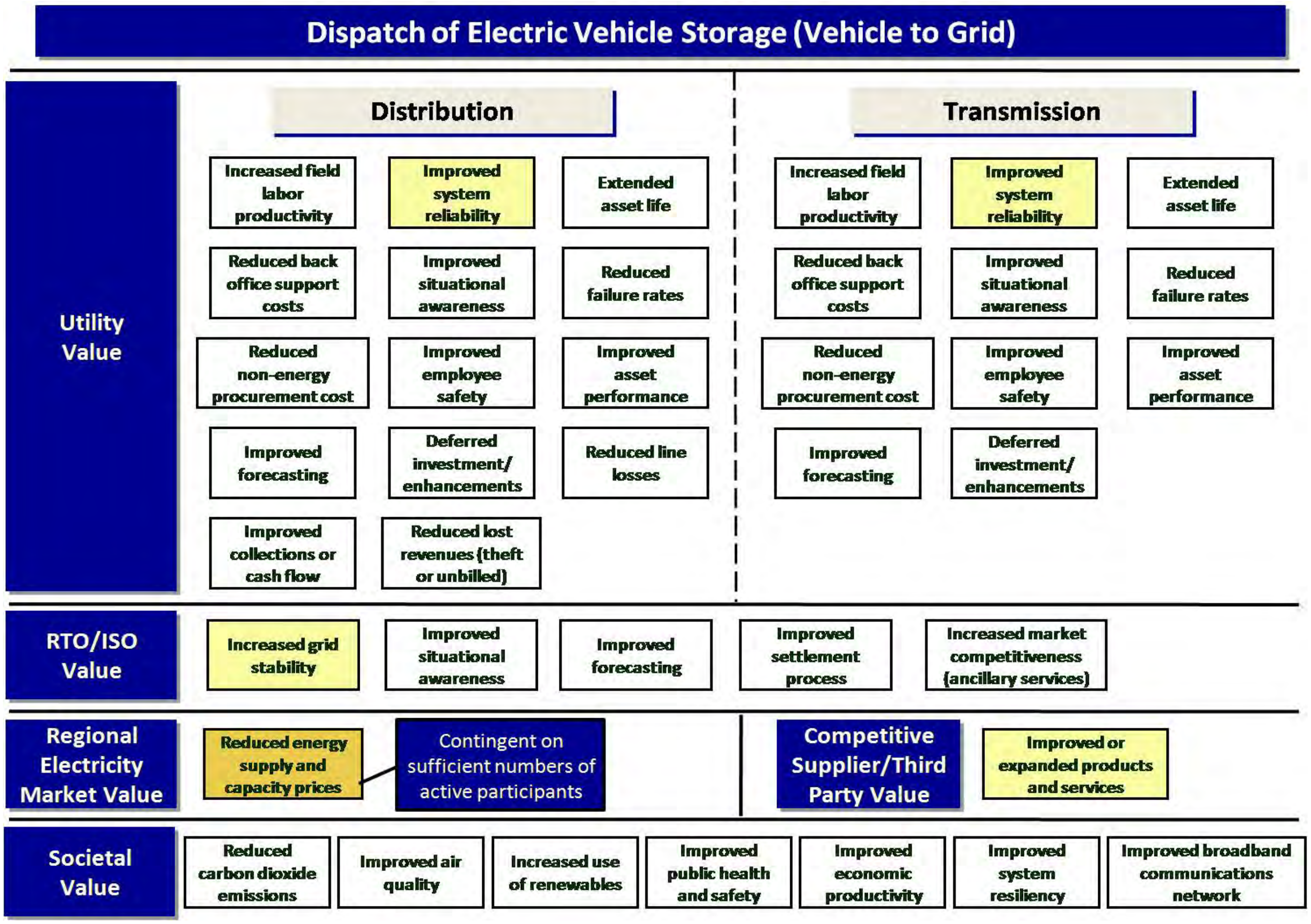
This application is in its infancy and requires standards and technology development for vehicle communications and in-premises communications. Improved battery life cycle and a vehicle charging infrastructure are also essential.

Potential Sources of Costs

To enable this application, a communications system, demand response system and a distribution management system are required. Customers also would require a communicating vehicle charging portal which could be part of the car or a separate device.

Potential Sources of Benefits and Beneficiaries





The following primary potential benefits have been identified:

- **Regional Electricity Market**
  - Reduced energy supply and capacity prices -- Customers would benefit from reduced energy prices as vehicle storage could be used during times when energy costs are high and dispatch of vehicle based storage might be used to reduce system peaks.

Potential secondary sources of benefits include:

- **Customers**
  - Increased ability to manage energy costs – Customers would voluntarily participate in V2G transactions based on economic considerations
  - Enhanced services to the customer – Improved interfaces would allow customers to define their preferences for when they provide energy, the level of vehicle charge to maintain, and V2G price point

- Facilitated customer generation – Customers gain additional benefit from their electric vehicles by selling stored energy
- Improved system reliability– Customers benefit from the increased reliability provided by widespread V2G programs

➢ **Utilities**

- Improved system reliability – Utilities have access to additional resources to meet demand

➢ **RTO/ISO**

- Increased grid stability – Assuming wide support, V2G can be dispatched as needed to provide grid support

➢ **Competitive Suppliers and Third Parties**

- Improved/expanded products and services – Third parties could aggregate groups of customers in V2G programs and provide stored energy back to the grid. Many new products and services built around the V2G opportunity could emerge over time.

Potential Negative Impacts

A potential negative impact for this application is the reduction of customers' battery life when used to provide energy to the grid. Batteries have a limited number of charge-discharge cycles and V2G decreases the useful life of the battery. The price paid to customers for their stored electricity has to include the value of incremental battery wear.

Transmission Applications

The transmission applications group focuses on scenarios that improve the reliability and security of the bulk transmission system.

Transmission Applications include:

- Wide Area (Phasor) Measurement
- Wide Scale Outage Recovery
- Enhanced Physical Security.

Wide Area (Phasor) Measurement

Description

Improved communications and sensors allow better visibility and decision making for transmission system operations.

Phasor measurement units in substations can measure system phase angles 30 times per second. The data is transmitted back to a control center to determine phase angle differences at various points of the grid. The phase angle differences provide improved situational awareness and should improve grid stability.

The technology for this application is mature and wide area measurement devices and systems are being increasingly deployed.

Potential Sources of Costs

Utilities must install phasor measurement devices, upgrade communications and upgrade their transmission control systems.

Potential Sources of Benefits and Beneficiaries

Wide Area (Phasor) Measurement

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability						
	Improved power quality						

Wide Area (Phasor) Measurement

Utility Value

Distribution

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements
- Reduced line losses
- Improved collections or cash flow
- Reduced lost revenues (theft or unbilled)

Transmission

- Increased field labor productivity
- Improved system reliability
- Extended asset life
- Reduced back office support costs
- Improved situational awareness
- Reduced failure rates
- Reduced non-energy procurement cost
- Improved employee safety
- Improved asset performance
- Improved forecasting
- Deferred investment/ enhancements

RTO/ISO Value

- Increased grid stability
- Improved situational awareness
- Improved forecasting
- Improved settlement process
- Increased market competitiveness (ancillary services)

Regional Electricity Market Value

- Reduced energy supply and capacity prices

Competitive Supplier/Third Party Value

- Improved or expanded products and services

Societal Value

- Reduced carbon dioxide emissions
- Improved air quality
- Increased use of renewables
- Improved public health and safety
- Improved economic productivity
- Improved system resiliency
- Improved broadband communications network

The following primary potential benefits have been identified:

- **Utilities**
  - Improved situational awareness – greater understanding of transmission system conditions
- **RTO/ISO**
  - Increased grid stability – allows controllers to rapidly respond to adverse system conditions
  - Improved situational awareness – provides greater transmission system condition information.

Potential secondary sources of benefits include:

- **Customers**
  - Improved system reliability – Customer may benefit from reduced outages or shorter outage durations
- **Utilities**
  - Improved system reliability – Improved situational awareness allows for controllers to rapidly respond to adverse system conditions
- **Society**
  - Improved public health and safety – Increased transmission reliability prevents lengthy, wide spread outages
  - Improved economic productivity – Increased transmission reliability prevents lengthy, wide spread outages.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Wide Scale Outage Recovery

Description

Smart grid devices at the transmission and distribution system level allow for better measurement and control of the electrical system when restoring from a wide scale outage. Utilities and the RTO can use improved sensing devices to measure existing grid conditions and more discrete controls to improve speed of restoration. This application also includes improved fault location.

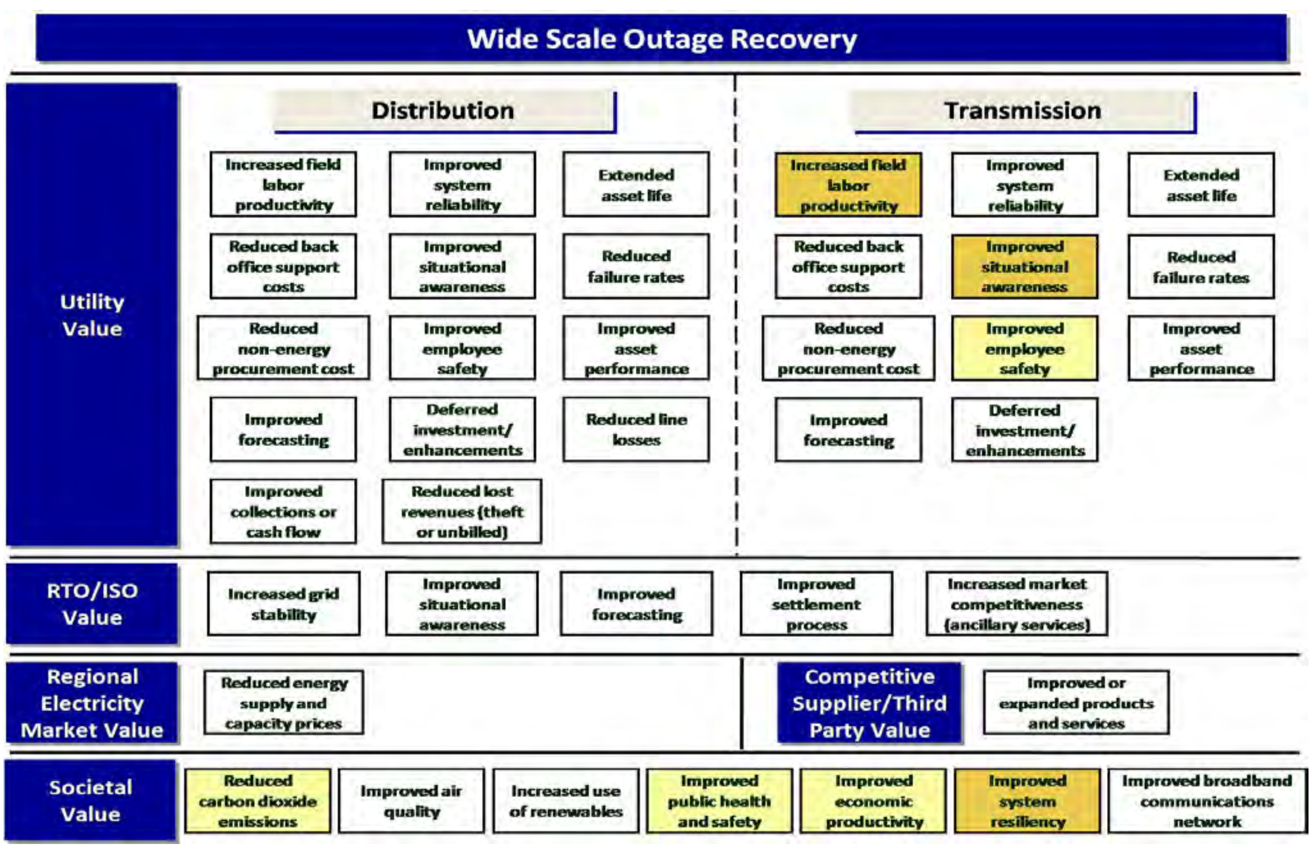
Potential Sources of Costs

Utilities will require additional switching and sensing devices and expanded field communications.

Potential Sources of Benefits and Beneficiaries

Wide Scale Outage Recovery

Customer Groups		Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	○	○	○	○	○	○
	Improved power quality						



The following primary potential benefits have been identified:

- **Utilities**
  - Increased field labor productivity – Utilities can use improved fault location to increase field crew efficiency
  - Improved situational awareness – Increased sensing capability
- **RTO/ISO**
  - Improved situational awareness – Increased sensing capability
- **Society**
  - Improved system resiliency (disaster recovery) – Improved sensing and control reduces outage impact and allows for quicker outage recovery.

Potential secondary sources of benefits include:

- **Customers**
  - Improved system reliability– Quicker outage recovery
- **Utilities**
  - Improved employee safety – Field crews spend less time in restoration efforts
- **Society**
  - Reduced carbon dioxide emissions – This benefit is likely to be minor and for this specific application is obtained by the reduction in the utility's use of vehicles for field crews
  - Improved public health and safety – Reduced outage durations improve public safety
  - Improved economic productivity – Quicker outage recovery.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Enhanced Physical Security

Description

Deployment of communications associated with other smart grid applications may provide the opportunity for enhanced physical security of substations and their assets. This application can apply to both transmission and distribution system assets. This application can overlap with the Asset Condition Monitoring application if infrared capable cameras are used for both security surveillance and asset monitoring. This application uses some existing technologies and could leverage the expansion of communications associated with other smart grid applications.

The basic sensing and camera devices associated with enhanced physical security are mature technologies.

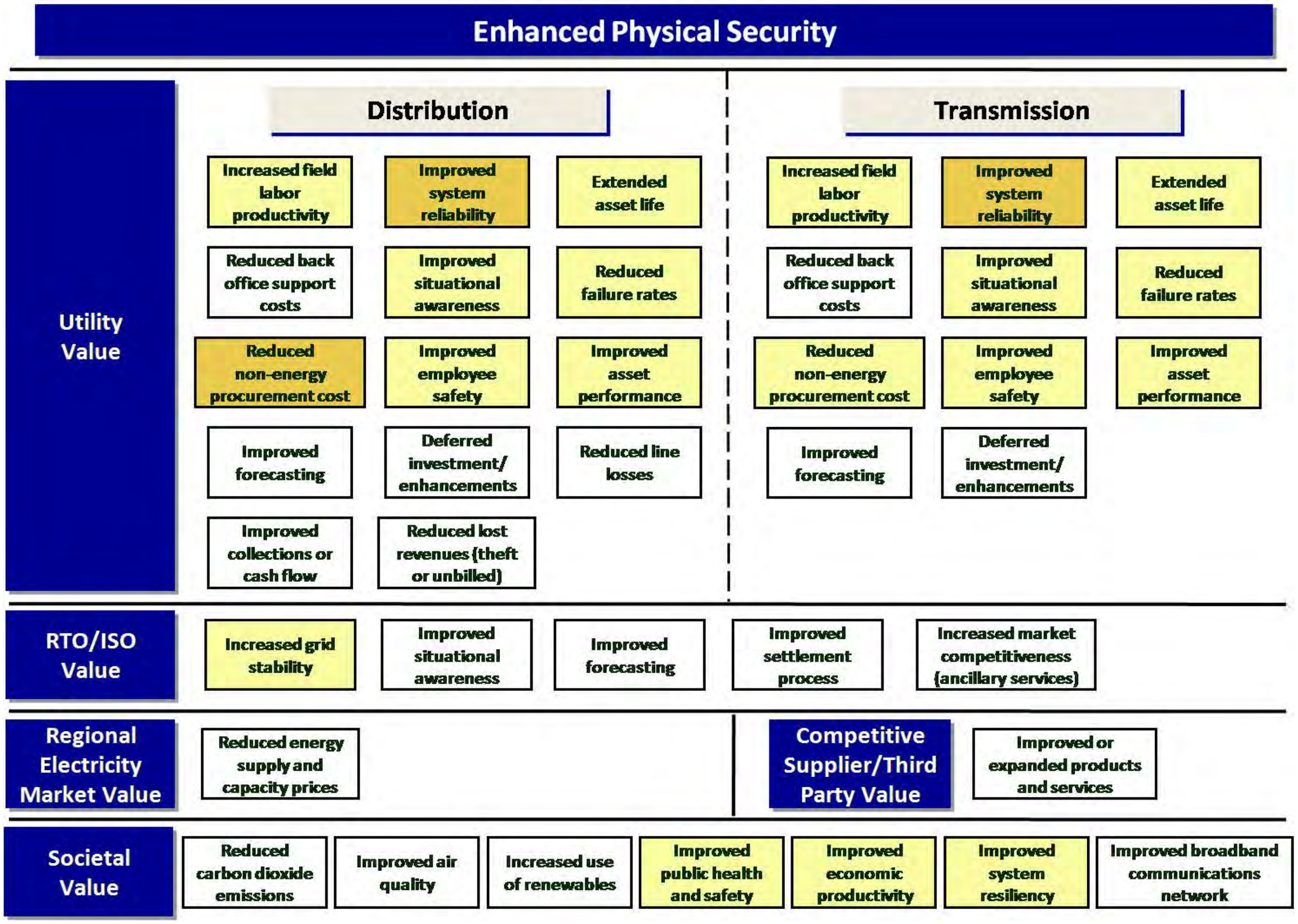
Potential Sources of Costs

The utility will require access control systems, cameras, and a high capacity network.

Potential Sources of Benefits and Beneficiaries

Enhanced Physical Security

	Customer Groups	Res/Small Bus, Active	Res/Sm Bus, Pass	Med Bus, Active	Med Bus, Passive	Large Bus, Active	Large Bus, Passive
Customer Value	Reduced energy usage (efficiency)						
	Reduced energy usage (conservation)						
	Increased ability to manage energy cost						
	Enhanced services to the customer						
	Improved information availability						
	Facilitated customer generation						
	Improved system reliability	●	●	●	●	●	●
	Improved power quality						



The following primary potential benefits have been identified:

- **Customers**
  - Improved system reliability– Assumes that improved security prevents outages
- **Utilities**
  - Improved system reliability – Assumes that improved security prevents outages
  - Reduced procurement cost – This benefit is achieved by reducing damage to utility assets.

Potential secondary sources of benefits include:

- **Utilities**
  - Increased field labor productivity – Utilities will have to spend less time repairing and replacing damage due to unauthorized access
  - Extended asset life – by reducing damage to utility assets
  - Reduced failure rates – by reducing damage to utility assets
  - Improved asset performance – by reducing damage to utility assets

- Improved employee safety – Employees will be less exposed to damaged and potentially dangerous equipment
- Improved situational awareness – Enhanced security systems can provide additional, near real-time data to the utility

- **RTO/ISO**
  - Increased grid stability – if improved security prevents outages
- **Society**
  - Improved public health and safety – if improved security prevents outages
  - Improved economic productivity – if improved security prevents outages
  - Improved system resiliency (disaster recovery) – Enhanced security can enhance system resiliency, but may have little impact on disaster recovery.

Potential Negative Impacts

No negative impacts related to this application have been identified.

Consumer Policy Issues

Objectives and Purpose

Deployment of smart grid technologies would have significant implications for many areas of state regulatory policy affecting the relationships between utilities, consumers, potential suppliers, and other parties. These "consumer issues" are the focus of this chapter of the Report. Specifically, the purpose of this chapter is to address, in whole or in part, the following foundational policies enumerated by the Commission in the ISSGC initiation order:

5) Implications of smart grid technology for future policies regarding rate design, consumer protection, and customer choice;

6) Effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation;

7) Consumer education and dissemination of information about smart grid technologies, demand response programs and alternative rate structures;

8) Access by electricity market participants to smart grid functionalities;

11) Mechanisms to flow through to customers any utility smart grid revenues;

12) Adoption of new demand response programs.

The objectives of this chapter include the following:

- Assess the effect of smart grid deployment on existing consumer policies
- Identify new policy issues that would arise from smart grid deployment
- Recommend policies intended to result in maximized consumer benefits and minimized negative impacts
- Consider whether investment in smart grid technology has implications for regulatory cost recovery policies, and envision options that might address the concerns of both customers and utilities

Scope

A wide range of existing state regulatory policies may need to be reexamined in light of new smart grid functionalities and new policies may be appropriate where current ones prove to be inadequate. The Collaborative examined six areas of consumer policy directly affected by the smart grid applications identified in the Smart Grid Applications chapter and relevant to the foundational policies listed above:

- Data Privacy and Data Access Policy
- Competitive Retail Market Structure Policy
- Remote Connection and Disconnection Policy

- Customer Prepayment Policy
- Utility Rates Policy in a Smart Grid Environment
- Smart Grid Consumer Education

In addition to the above policy areas, a threshold issue implicated by the reference to "rate design" in foundational policy #5 was identified by stakeholders as potentially fruitful for the Collaborative to address: equitable policies for recovery of smart grid costs. While acknowledging at the outset that a consensus on this contentious issue (which was initially litigated in Dockets 07-0566 and 07-0585) would not likely be achieved in this Collaborative process, stakeholders agreed there would be value for all sides and for the Commission if the Collaborative were to identify key cost recovery issues, exchange differing views, and attempt to reach a common understanding of legitimate concerns and regulatory options.

Finally, this chapter of the Report addresses the foundational policy identified by the Commission regarding the interplay between smart grid deployment and existing statutory requirements for programs to improve energy efficiency, reduce peak demands, and incorporate growing amounts of renewable energy resources.

Data Privacy and Data Access Policy

Stakeholders agree that successful resolution of issues regarding the availability and protection of AMI-enabled data access is crucial to smart grid deployment and operation. Certain issues related to data security are being addressed at the national level. The Energy Independence and Security Act (EISA) of 2007 directed the National Institute of Standards and Technology (NIST) to create an Interoperability Framework for the U.S. smart grid, and NIST in turn created the national Smart Grid Interoperability Panel (SGIP). However, as the following section articulates, stakeholders agree that state policy with regard to data privacy and data access must take a step beyond technical standards and cyber security to address how the data of individuals and groups of consumers should be treated and protected by all parties with access to them.

Discussion

One key feature of a smart grid is its ability to capture and transmit information about system conditions and customer usage in near-real-time. The vast quantity of data made available by smart grid technology contains significantly more and new private information about individual consumption and consumer behavior. That information must be protected from unauthorized collection, release, sharing, use or retention.

Several different customer-specific data sets (as defined below) are captured by AMI systems, including:

- Meter Data – all data captured by/for the AMI system, including interval usage data, voltage/power quality readings, meter event data, acknowledgement/verification of message transmissions or price signals/compliance. Although Customer Data may be accessible by the AMI meter via HAN interface, Meter Data does not include customer data.

- Usage Data – Usage Data is the interval energy and demand data captured by the AMI meter and transmitted to the Meter Data Management System. Usage Data is a subset of Meter Data that does not include voltage readings, meter event data, acknowledgements and verifications.

- Billing Data – all data required for bill calculation, including pricing information, compliance confirmations to demand response pricing signals, net metering data, and distributed resource coordination.

- Customer Data – HAN-level and appliance-level usage and in-premises energy management data not required for AMI system operations, demand response, or distributed resource coordination.

Policy Recommendations

Utilities and other parties must be required to engage in responsible, reliable and accountable management of all AMI-derived data to protect customers from unauthorized access or improper use of those data. Therefore, with regard to residential and small commercial utility customers,[31] the following policies are recommended by ISSGC:

Customer-Specific Data

1. AMI systems should be designed so that customers can securely retrieve Usage Data directly and in near-real-time from the meter securely through an in-premises device. This objective may require that any in-home device that connects to the utility's meter to be certified or approved to comply with cyber-security standards or operational characteristics so that the utility's Meter Data is not compromised.
2. Customers should have access to collected historical Usage Data and Billing Data for a reasonable period of time, via a utility-provided web portal.
3. Customer authorization should continue to be required for access to any customer-specific Meter Data by a third party. Third-party use of Meter Data should be limited to the specific purposes disclosed by the third party to the customer.
4. Customers need to be fully informed about the information to which they are granting access. Third parties must fully disclose in plain language (whether disclosure is oral,

[31] As defined in the PUA, "small commercial customers" have annual usage of less than 15,000 kWh.

written, or electronic) the scope, duration, and purpose(s) of the requested access to customer-specific Meter Data. Any customer complaints regarding access to or use of data by an ARES or other jurisdictional third party should be subject to the Commission complaint process. The need for additional consumer protections regarding authorized use of data by entities not jurisdictional to the Commission should be studied and implemented through legislation if necessary.

5. The utility should provide electronic access to Billing Data and Usage Data to customer-authorized third parties within a reasonable period of time from receipt of authorization. Any charges for such data access should be outlined in the tariff and reflected in regulated revenue.

6. A service and supply agreement with a customer should contain an explicit authorization for the ARES to access and use Usage Data and Billing Data for billing purposes. Any authorization to access historical data or other information not directly related to billing and collection should be explicitly stated in an agreement. Cancellation or expiration of the supply agreement should also revoke a supplier's access rights to the customer's data. Any supply agreement should also include explicit authorization to provide this information to an ISO, if the ARES is participating in the ISO market by providing demand response resources. Data made available to customer-authorized third parties should be the same information that is provided to the customer. The utility should not be required to customize or disaggregate data.

7. The utility should be responsible for protecting all Meter Data in its possession from unauthorized release. Similarly, a customer-authorized third party that receives customer Meter Data should be responsible for protecting that data from unauthorized release.

8. The utility should be allowed to use customer-specific Meter Data to support operation of utility systems and the electricity transmission and distribution network and/or as required by state and federal authorities.

9. The utility should be allowed to use customer-specific Meter Data to solicit participation in Commission-approved demand response and energy efficiency programs, including comparisons between individual customer usage and aggregated community usage, and comparisons to typical usage of other similar dwellings, which comparisons should only be available to an individual customer.

10. Stakeholders agree that the utility should only be allowed to make use of the Meter Data and Customer Data for offering a competitive service or share such information with any affiliated or unaffiliated entity to the extent allowed by, and consistent with the Illinois Public Utilities Act, the ICC's Integrated Distribution Company rules, the utility's approved IDC Implementation Plan, the Illinois Consumer Fraud and Deceptive Business Practices Act and other applicable laws and ICC rules and orders. Some stakeholders further believe that if a utility or its affiliate offers competitive services, they should not, under any circumstances, be allowed to use customer Meter Data in offering those services without affirmative customer authorization and application of third party disclosure requirements.

11. Governmental units should not have unauthorized access to customer-specific data except insofar as some customer-specific data (such as regarding outages, disconnections, and other information potentially affecting public health and safety) is already shared with government by the utility under existing law, policies and agreements. [See e.g., 220 ILCS 5/8-202(b)] The utility should adopt policies and procedures that comply with state and federal law to respond appropriately to law enforcement requests for AMI-derived data.

12. Customers must be educated and informed about what it means to allow access to AMI-derived data. *[This issue is further addressed in the Consumer Education section of this chapter.]*

Aggregated Data

13. If a utility provides third parties (e.g., governmental entities, academics, RTO/ISO) with aggregated AMI Meter Data sets, it must take reasonable measures to protect the identity of individual customer data. Where individual customer data privacy cannot reasonably be assured, the third party should obtain authorization from the customer for access to identifiable customer data prior to its release by the utility.

Competitive Retail Market Structure Policy

Background

Illinois law provides for retail competition in residential electricity supply services as well as for supply to commercial and industrial customers (see: 220 ILCS 5/16 of the Public Utilities Act (PUA)). Residential customers may choose to take energy supply services from the utility or through contracts with third-party providers, to the extent that there are such suppliers offering such services.

The Illinois Commerce Commission (Commission) has jurisdiction over certain aspects of competitive electricity marketing (under Sec. 16-115A and 16-115B of the PUA and Part 451 of Administrative Code covering Alternative Retail Electric Suppliers (ARES), Sec. 16-115C and Part 454 covering Agents, Brokers and Consultants, and Part 460 covering Meter Service Providers). The Commission has limited, if any, jurisdiction over post-meter devices (PMD) and services offered by non-utility providers, but, in the view of the Collaborative, should exercise its jurisdiction or be given jurisdiction over the terms and conditions offered by a utility that governs the connection of such devices to its metering system. However, other Illinois agencies and law enforcement authorities have jurisdiction over such providers under consumer protection and unfair trade practice laws.

Utilities are required to provide only legally mandated delivery services as per Sec 16-103(e) of PUA*:*

> *(e) The Commission shall not require an electric utility to offer any tariffed service other than the services required by this Section, and shall not require an electric utility to offer any competitive service.* (Source: P.A. 90-561, eff. 12-16-97.)

Utilities must continue to provide bundled service to residential customers as per Sec. 16-103(c) of PUA:

> *(c) Notwithstanding any other provision of this Article, each electric utility shall continue offering to all residential customers and to all small commercial retail customers in its service area, as a tariffed service, bundled electric power and energy delivered to the customer's premises consistent with the bundled utility service provided by the electric utility on the effective date of this amendatory Act of 1997…*

In serving "Eligible Customers," including residential and small commercial customers choosing to purchase utility supply, ComEd and the Ameren Illinois Utilities are required to procure electricity as specified in annual procurement plans prepared by the Illinois Power Agency (IPA) and approved by the Commission. As per Sec. 1-5 of the IPA Act, these procurement plans are intended to "ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability" (20 ILCS 3855/1-5(A))

ComEd and the Ameren Illinois Utilities have each elected to become an Independent Distribution Company (IDC), subject to rules stating, in relevant part, that they "shall not promote, advertise or market with regard to the offering or provision of any retail electric supply service." 83 Ill. Admin. Code 452.240(a). However, these rules do not preclude "advertising or marketing permissible IDC services other than retail electric supply services." 83 Ill. Admin. Code 452.240(b).

Discussion

How a smart grid enabled energy management market will evolve – its dynamics, pace, and scope of products and services -- cannot be predicted. In the market's current embryonic state, many vendors of hardware, software, supply and other services are researching, developing, and beginning to market products in anticipation of wide AMI deployment. Simultaneously, national standards and protocols are being set to achieve the seamless interoperability that is vital to a safe, reliable, well-functioning, and consumer-friendly smart grid and crucial to the emergence of effectively competitive markets in smart grid-enabled products and services.

Individual customers may or may not experience specific or identifiable benefits from enhanced energy supply products and services facilitated by smart grid deployment, regardless of supplier. This disparity in potential benefits may result in some customers paying higher bills for the costs of smart grid investments without experiencing any identifiable benefits in the form of lower individual bills or lower electricity prices overall. Other customers may experience individual savings greater than costs that may be allocated to them.

Furthermore, customers who lack sufficient experience, knowledge and information to evaluate options and make informed choices are vulnerable to manipulation and may make choices that result in unexpected charges on their bills. Without adequate customer education and consumer protections addressing such issues as contract termination fees and transparency in products and pricing, the likely variance between expected and realized benefits can potentially lead to general mistrust of energy markets, smart grid investments, and the regulatory system.

Extensive and ongoing consumer education is essential to achieving the potential benefits of smart grid deployment and to enabling informed public assessment of its value. *(These issues are further addressed in the Consumer Education section of this Report.)* With regard to choices of electricity products and services in an AMI environment, consumers would benefit from understanding, at a minimum:

- how the current wholesale market structure produces time-variant market prices of electricity, and how usage during peak hours leads to reliance on more costly capacity resources;
- how an AMI meter provides information that can facilitate energy management, demand response programs, and usage reduction;
- the potential uses, costs and benefits of an AMI metering system and related equipment;
- the factors to consider when evaluating rate options, including time-variant rate options, peak time rebates, critical peak pricing, and direct load control programs.

The key market structure policy questions within the scope of state regulatory jurisdiction are related to the role of regulated utilities in the provision of products and services to utility customers. *[Choice of rate options for those taking utility supply service is addressed in the Utility Rates Policy In A Smart Grid Environment section of this Chapter].* Provision of hardware to customers by a utility may pose regulatory and administrative challenges to address issues of potential cross-subsidy, competitive neutrality, and accounting. In fulfilling its regulatory functions, the ICC has extensive experience in reviewing and ruling on cost-tracking and related issues.

The General Assembly has created an Office of Retail Market Development "dedicated to the task of actively seeking out ways to promote retail competition in Illinois to benefit all Illinois consumers." (Sec. 20-110 of the PUA). However, since retail residential electric competition, although allowed by law since 2002, is still in the very early stages of development in Illinois, there is no Illinois-specific information about whether the residential offerings of competitive suppliers would advance the goals of energy efficiency and reduced peak energy usage, which are part of the potential consumer benefits of AMI.

Under state law, utilities provide mandated energy efficiency and demand response programs that may benefit from the provision of Post-Meter Devices (PMD) enabled by smart grid technology to achieve the goals of those programs.

Policy Recommendations

1. AMI systems deployed by utilities in Illinois should allow consumers to easily connect in-home devices and networks, providing a full range of opportunities for customers to employ tools to optimize cost effective demand response and achieve energy management objectives. Stakeholders have not reached consensus as to whether any costs of PMD should be considered for recovery through base rates. Any proposal to subsidize or fund the purchase of PMD for customers should, at a minimum, reflect a cost benefit analysis that includes the costs associated with installing and maintaining such devices, the projected demand response or usage reduction benefits that will occur over the estimated life of the device, and the cost of educating customers about the use of the device.

2. To the extent that PMDs are found by the Commission to be necessary to capture AMI customer benefits, and that a demonstrable business case is made for utility involvement in their provision to consumers, policies to facilitate access to PMDs may be warranted. In assessing how utilities could aid customers in obtaining PMDs without impeding PMD market development, the Commission should compare the projected effects of direct utility provision of PMDs with the projected effects of using non-utility distribution channels.

3. Any provision of PMD by a utility is subject to IDC rules and should not require the customer to purchase utility supply in order to receive and make use of the PMD. To the extent practicable, PMD should be capable of presenting billing and pricing information from either a utility or an ARES.

4. Any PMD subsidies that may be deemed by the Commission to be appropriate in order to achieve smart grid objectives should be competitively neutral with respect to electricity supplier.

5. Smart grid policies should be consistent with but not dependent upon the state's policy to foster the development of retail electric competition. In the evaluation of proposed utility rate offerings and demand response programs, the Commission should be guided by actual experience concerning the interplay between such programs and the development of retail competition. In determining smart grid policy, the Commission should consider the effect of such policies on the development of retail competition and the effect of retail competition on achievement of the goals of smart grid deployment.

6. In order to protect consumers and allow the nascent market in smart grid-enabled products and services to develop, the Commission and other consumer protection authorities should closely monitor consumer complaints in order to quickly address problems and issues that may need formal regulatory attention. Where preventive regulation is needed, appropriate consumer protections should be ordered or enacted.

Remote Connection and Disconnection Policy

Issues associated with remote disconnection of electricity service were highly contentious among Collaborative participants. As the following agreed language details, stakeholders were not able to reach consensus recommendations to the Commission about how to address these issues, nor what would be the implications for utility connection and disconnection practices of AMI deployment under today's rules.

Discussion

Advanced meters typically include an integrated service switch that can be opened or closed remotely by a signal from the utility. This functionality allows the utility to connect or disconnect service upon request of a customer, to disconnect service for non-payment, and to reconnect service after payment is received.

For a utility company, the ability to switch service on and off without a "truck roll" and a premises visit would result in operational savings for connecting or disconnecting service. It is also possible that other societal benefits would also follow from the reduction in vehicle miles traveled, particularly if the vehicles are fossil-fueled. Some stakeholders argue that remote disconnection also would reduce dangers to utility employees.

The implications for customers of remote switching vary for the different types of circumstances under which utilities connect and disconnect service. For a new service applicant or an existing customer moving to a different dwelling unit, remote connection would mean quicker and easier changes in service, because contingencies such as field crew availability, weather, and traffic would no longer affect connection appointments or commitments to connect service (where such appointments or commitments are necessary today) to establish a new account. Remote connection would allow service to be more reliably initiated on a preferred date, and therefore should mean an accurate and precise initial bill for service. Similarly, a customer voluntarily discontinuing service at an address could schedule the disconnection for a particular time and receive an accurate final bill for service at the location. These more accurate and timely transfers of payment responsibility for service at a particular meter could be anticipated to minimize the amount of unbilled service, the cost for which is reflected in both the distribution and supply portion of customers' bills.

For customers whose service may be discontinued involuntarily due to nonpayment, the implications of a remote service switch are quite different. Some stakeholders assert that this functionality would result in an increase in the volume of disconnections for nonpayment. This is predicted to occur because utilities will not have to prioritize disconnections or take into account the costs to schedule a premise visit to turn off service at the meter. Furthermore, some argue that automation of the disconnection process could result in harm to the health and safety of some customers if the utility does not make a premises visit and attempt to contact the customer or interact with residents who may be present at the dwelling. This may be particularly true for elderly customers, those with disabilities, or those vulnerable to health and safety risks or medical emergencies associated with the loss of power. Other stakeholders do not agree that health and safety risks would increase due to remote disconnections. In addition, they point to the potential for better management of arrears balances if more streamlined, consistent, and well understood disconnection practices were put in place.

Remote disconnection from an essential service raises a number of policy issues. Chief among them is the question of what, if any, changes would be needed with respect to a utility's existing obligation to attempt contact with a customer at the time of an on-site disconnection for nonpayment. Current technology requires a site visit to disconnect service, and current rules require that "A utility shall attempt to advise the customer that service is being discontinued by directing its employee making the disconnection to contact the customer at the time service is being discontinued." (Section 280.130(d)) Stakeholders do not have a common understanding about what utility practices would comply with this rule under existing disconnection technology and procedures. Stakeholders disagree on whether an on-site attempt at personal contact with the customer should be required if a remote capability were to obviate the need for a site visit to disconnect service for nonpayment.

Proponents of a required site visit prior to disconnection for non-payment argue that disconnection of electric service is a potentially harmful act that should be avoided where possible and that a site visit and attempt to contact the customer is an important consumer protection that should not be eliminated. They also contend that there is no other way to assure that the customer has received the required notice and is aware of the impending action. Because loss of electric service means the end of access to essential functions such as light, refrigeration, heating, and cooling, these stakeholders argue that disconnection poses such a threat to personal health and safety that the utility should demonstrate that it has taken every possible step to contact the customer prior to taking this action. Moreover, a site visit might reveal mitigating circumstances or a medical or mental health situation that could make a delay in disconnection appropriate for a particular customer. A site visit also gives the utility employee the opportunity to observe safety issues not otherwise detectable. Proponents of a mandatory premises visit for each disconnection acknowledge that it would have a cost but believe that the benefits to the utility, society and individual customers exceed the costs avoided through remote disconnection and the elimination of any attempt at contact at the time of disconnection for nonpayment. In addition, some stakeholders are concerned that remote action by the central office may be more prone to error that might otherwise be detected by field personnel. Finally, these stakeholders point to the fact that regulatory policies in certain other states require a mandatory premises visit by the utility and acceptance of credit card payment from a customer to avoid disconnection.

Other stakeholders are skeptical of both the particular benefit of a utility site visit to a customer facing disconnection and the general benefit to other ratepayers from whom the reasonable costs of having a utility employee attempt face-to-face contact would be recovered. They assert that the anticipated operational cost savings from remote service switching would be largely offset or eliminated by requiring a utility make site visits prior to executing remote disconnections. They question the value of a visit if its only purpose is to inform the customer of an impending disconnection, and are concerned by the potential reaction of the customer to the utility employee at the door. If the visit is intended to allow the customer an opportunity to avoid disconnection, and/or for the utility representative to make a decision as to whether or not the disconnection would be carried out, additional concerns arise. These stakeholders would seek guidance as to the specific criteria to be used by the employee to make such judgments, as well as the nature of the oversight to ensure non-discrimination and uniform application of policy. These stakeholders argue that remote disconnection may be less susceptible to error than on-site disconnection. They question why the advent of new disconnection technology would be reason for new regulatory policy requiring utility field personnel to accept payment for service. Furthermore, they contend that any potential negative consequences of remote disconnection could be addressed effectively and at reasonable expense through means such as multiple contacts to payment-challenged customers using telephonic and electronic means, in addition to mailed notices.

The issue of prompt connection of electric service is also raised by many stakeholders. They assert that if service can be disconnected immediately through operation of a remote service switch, it can be connected just as quickly, and that the Commission should add rules that require all connections – especially reconnections – to be carried out expeditiously, within a specific time period. The role and responsibilities of third parties involved in bill payments, such as collection agents and community action agencies, also might have to be reconsidered in this context.

The ComEd AMI pilot program may provide information that will be relevant to consideration of regulatory issues that would arise in a full-scale deployment of AMI, including policies regarding remote connection, disconnection, and reconnection of service by the utility. Implementation of AMI's remote switching capabilities should be the subject of a comprehensive reassessment of relevant Commission policies and utility practices, including consumer education.

Stakeholders emphasize that the Commission should study, support and implement initiatives to reduce the incidence of disconnection and thereby minimize both the harm to individuals and the social costs to the community of households living without essential electricity service.

Customer Prepayment Policy

Discussion

A prepayment program provides customers with an option to purchase electricity in advance of its use by purchasing a specified amount of electricity at a specified price. Such programs typically include automatic disconnection of service when the customer's usage exceeds the amount of electricity purchased. Prepayment can serve as an alternative to deposit requirements for utility service, and may reduce the utility's credit and collection costs, as well as provide a structure to assist customers in reducing their electricity usage. However, as detailed below, prepayment for utility service also may have other effects that raise significant social and regulatory issues.

Prepayment offers a potential for reduced electricity bills for participants, only if utility cost savings due to prepayment (billing, collection, and receivables) are greater than the costs of operating the prepayment program and the reduced costs are reflected in participants' rates. Moreover, operation of a prepayment program requires: a) an in-home device to display the customer's actual usage and remaining credit, b) a means by which customers may purchase credits and have them recognized by the device, and c) a link between the device and the utility's meter so that the device can signal the meter and the utility when credit is exhausted or restored. The administrative and equipment costs associated with a prepayment program may be high relative to the small incremental savings realized by the operating utility. However, AMI deployment may reduce or eliminate the need for additional hardware.

The primary technological challenges for AMI-based prepayment rest with modifications to utility back office systems and processes. A standard smart meter equipped with an integrated service switch and communicating with an in-premises device can provide customers with continual measurement of and access to real-time energy usage and cost information as well as provide the utility automatic disconnection and reconnection capabilities, in accordance with approved prepayment policies.

Aside from the issues noted above, many stakeholders remain skeptical of or opposed to customer prepayment because of concerns that include the following:

1. Prepayment raises social policy issues about equal access for all households to an essential service. Customers with poor credit history or with unaffordable arrearages could find prepayment to be their only means to acquire and maintain access to electricity. This could be a violation of the law prohibiting discrimination in provision of utility service.

2. Immediate and remote disconnection when an account balance "runs to zero" could place customer health or safety at risk, particularly if Part 280 provisions prohibiting disconnection during extreme weather conditions were not in force for customers on a prepayment program.

3. Incremental costs to support customer prepayment may offset any cost savings, raising cost allocation issues and/or increasing the cost of prepayment service over traditional rates, with potential adverse effects on vulnerable populations unable to post deposits.

4. If it were technologically feasible and allowed by regulation for electricity prepayment to be offered by non-utility entities, third parties could market prepayment in a predatory way to customers who have been disconnected or who are unable to qualify for utility credit and lack funds for a deposit.

Policy Recommendations

Stakeholders are generally skeptical about the potential value of a customer prepayment program. A fully-functional AMI-enabled customer prepayment program has not yet been demonstrated in the U.S. and significant consumer protection issues exist. Any prepayment program considered for implementation in Illinois must be strictly voluntary, and prior to considering approval of any such utility program the Commission should require:

1. development of an Illinois-specific cost-benefit analysis showing net system and individual benefits from customer prepayment without adverse implications for customer health and welfare compared to the current system;

2. study of policies and procedures that could affect the rights of customers on a voluntary prepayment program to remain protected by seasonal disconnection moratoria (Sec 8-205, 8-206) medical disconnection prohibitions, and any other disconnection rules intended to protect consumer health and public safety;

3. consideration of the feasibility of customer options other than automatic disconnection if the account balance runs to zero;

4. implementation of rules to require and technological capabilities to enable immediate application of customer payments and the customer's access to utility service in a prompt manner;

5. an analysis of how fixed distribution costs would be recovered under the specific proposed program;

6. guidelines regarding marketing of prepayment programs, to ensure that customers are made aware of all mechanisms to retain utility service, including subsidies, payment plans, government-funded and utility-sponsored energy assistance programs, and other available options;

7. prohibition of the utility disconnecting service to a customer based upon request of a third party.

Utility Rates Policy in a Smart Grid Environment

Regardless of what metering technology is in place, Illinois law provides that customers not taking service designated by statute or found by the Commission to be "competitive" may purchase supply service from the utility, procured according to annual plans submitted by the Illinois Power Agency (IPA) and approved by the Illinois Commerce Commission. The discussions among stakeholders about what would be an appropriate "default" utility rate structure if AMI were deployed – the rate design that all customers start with and remain on if they don't affirmatively choose another option – and what, if any, rate options should be provided by the utility, were among the most contentious of all topics addressed by the ISSGC.

Under the current residential rate structure, customers generally pay the same marginal amount for each kilowatt-hour, regardless of when it is consumed.[32] That means that some of the kilowatt-hours are sold to customers at rates that are below the cost of procuring them, while others are sold above cost (the effect of which is that customers who use a higher than average proportion of their electricity during off-peak hours subsidize the energy supply of customers with peakier load profiles, at a magnitude dependent on the difference between peak and off-peak supply costs).

The average retail rates for a utility's electricity supply are reset each year after a procurement event conducted by an independent administrator under the approved IPA Plan. The IPA is encouraged to hedge the supply portfolio and reduce its exposure to short term price fluctuations by contracting for standard wholesale products of varying contract lengths for projected volumes and reserves. An IPA procurement plan also might include spot market purchases and demand response products if approved by the Commission. Contracts for "baseload" power executed pursuant to legislative mandate are presently a significant component of the IPA portfolio, but will expire by 2013. All customers also have the option of purchasing energy at real-time variable prices as procured by their utility from the regional wholesale energy market.[33]

With AMI in place, whether a particular rate design will result in higher or lower costs for a customer or identified group of customers is dependent on their volumes, usage patterns, abilities and motivation to modify load shapes, and interclass and intraclass cost allocations, including the extent to which assigned AMI costs are allocated on a fixed or volumetric basis.

Why is the default rate structure a contentious issue in the Collaborative, when stakeholders largely agree that customers should have freedom to choose alternative rates from a menu of options? Some stakeholders point to inertia (also known as "status quo bias") as a key factor inhibiting people from executing a decision to change rate plans, even if it is advantageous for them to do so. Some stakeholders express concerns that customers may not have sufficient information, understanding, or time to choose wisely from a series of options, and might assume

[32] Under some rate designs, there are differences in rates for volumes above certain levels, such as a reduced winter tailblock rate to make electric heat more affordable.

[33] Capacity charges are calculated separately based on the customer's peak or estimated peak demand

that the default rate provided by the utility is correct for them. Some stakeholders believe it is essential to move customers away from flat rates in order to maximize smart grid benefits associated with an improved overall customer load shape. Some believe the default rate structure should be designed to reduce or eliminate existing intraclass cross-subsidies. Some stakeholders believe that these subsidies are minimal and equitable and should be retained.

Underlying this discussion of default rates are different perspectives on what is "fair" and to what degree that is determined or influenced by perceived customer perceptions and preferences. In addition, stakeholders have different views on the degree to which residential and small commercial customers would respond positively to "overnight" changes in long-standing rate policies, regardless of whether customers would have a choice of rate structures.

While there are a wide range of views in the ISSGC on the appropriate default rate, there is general agreement among stakeholders that consumers with AMI should have easily accessible rate options, and that considerable effort should be put into ensuring that they understand how their choices may affect them. There is little support in the ISSGC for mandatory time-variant utility rates. There is no consensus on default rates, but stakeholders have agreed on the following language to describe their perspectives on utility rate policies in an AMI environment.

Discussion

Investment in AMI systems and other smart grid technologies is predicated on achieving a stream of benefits including utility operational savings, higher system performance and reliability, better integration of distributed resources and electric vehicles, as well as consumer cost savings due to reduced electricity usage, peak demand reductions and load shifting from high-cost to low-cost periods. Societal effects external to the regulated utility system, such as potential environmental benefits, may also be associated with smart grid deployment. Prior to approval of smart grid investment, the investment would be subjected to a utility-specific cost-benefit analysis which the Commission would use in its determination of whether or not specifically identified benefits and savings will exceed projected costs to ratepayers over a reasonable period of time. *[This issue is fully addressed in the Cost Benefit Framework chapter.]*

In order to achieve the benefits identified by a specific AMI proposal with regard to bill savings, specific programs and initiatives should be proposed by the utility. While any utility operational savings from smart grid investments should be reflected in regulated distribution system rates, two types of cost savings could reduce electricity commodity costs paid by customers: individual and systemic savings. Individual customers could lower their electricity bills if the amount they save by participating in AMI-enabled programs or by taking individual actions to reduce their consumption exceeds the costs of smart grid investment embedded in their rates. Systemic savings could occur if enough customers, in response to usage data, price information, and peak reduction incentives, modify their consumption patterns sufficiently to improve the system load shape, and that results in downward movement of peak market energy and capacity prices as well as potential mitigation of wholesale price volatility. However, these potential systemic effects must be evaluated to determine their likelihood and magnitude, as well as how these benefits would be monetized and to what extent they would be manifested on customer bills. If significant peak demand reductions were achieved, it is possible that additional consumer savings could accrue over time due to lower capacity costs and deferred or reduced investment in transmission and distribution system upgrades, although these potential effects would not be measurable.

While Illinois utilities already engage in ratepayer-funded and state-mandated activities and programs intended to reduce electricity consumption and improve load shapes, including direct load control and energy efficiency programs, AMI would allow interval usage data to be communicated between the utility and individual users either through a web-based program or through a secure connection to an in-premises device. This information would enable delivery of peak-time energy reduction programs, including pricing programs and rebates, and would allow customers to see changes in their usage consumption patterns.

Options to provide “eligible” (residential and small commercial) customers with access to pricing structures and programs for participating in ISO capacity, energy and ancillary service markets should be analyzed and considered in conjunction with relevant regulatory proceedings. Stakeholders agree that smart grid investment (even if utility-specific cost-benefit tests are favorable) may not realize its potential without ongoing education of consumers about how they might use more detailed usage information and other smart grid capabilities to advance their objectives related to electricity usage. *[This issue is more fully addressed in the Consumer Education section of this chapter.]*

Stakeholders hold strongly differing views on the degree to which default rate structures for residential and small commercial customers should reflect the time-variant prices enabled by AMI. Stakeholders look to the results of the ComEd AMI pilot and residential RTP programs for relevant information. The remainder of this document will describe these points of view using illustrative policies, and acknowledging variations around the illustrative policy.

One perspective holds that AMI deployment does not call for any change in the basic residential and small commercial[34] rate structure. In this view, regardless of meter technology, customers’ default rate should be their current (flat) rate, with the ability to opt-in to a dynamic or time-variant rate (offered by the utility or an ARES) in response to customer education programs or economic incentives. New utility dynamic pricing options or demand response programs should be submitted to the Commission for approval, accompanied by evidence of the costs and benefits of implementation, including customer education. The analysis should include an attempt to assess the effect of these new options and programs on customer bills by usage, customer demographics and other characteristics. An attempt should also be made to project the impact of these new options and programs on capacity and energy prices paid by residential and small commercial customers.

Some proponents of flat or fixed default rates argue that significant peak load reductions can be achieved through direct load control and other voluntary demand response programs, including time-variant rate options such as a peak time rebate program, without need for any change in underlying rate structures. According to these stakeholders, education of

[34] Small Commercial customer as defined in the PUA uses <15,000 kWh/year

consumers about demand response and efficiency choices can result in lower energy prices for all customers, particularly if programs are structured to benefit a broad range of customer profiles. Since not all customers have similar load shapes or levels of interest in energy management, sufficient resources to invest in energy management, or abilities to shift their electricity usage, not all customers would likely see a monetary benefit from choosing a dynamic pricing option.

Proponents of flat default rates also contend that education of customers about energy choices, the value of energy efficiency programs and the environmental cost of energy should be the first strategy used to achieve load-shape reform and energy reduction. Under this approach, customers who are interested in a dynamic price could opt-in to one of the approved pricing programs, while others would choose to remain on flat rates because of their own assessment of any bill impacts, need for price stability, and convenience trade-offs. Adherents to this view assert that most customers have limited familiarity with time-variant rates and have demonstrated their preference for the convenience and/or stability of a fixed rate in the implementation of time-based rate options in many states. Furthermore, they assert that customers who must use electricity for health related purposes during peak periods could be harmed by their inability to shift usage to cheaper times of day.

A contrasting position is taken by stakeholders who believe that default rates for customers with AMI meters should vary between time periods in order to better match retail rates with prices in the wholesale market. These stakeholders contend that flat rates provide no information to customers about the varying costs of electricity for peak and off peak usage, contain unseen hedge premiums, and provide no financial incentive to shift consumption to off-peak periods, resulting in higher average costs for all customers over time. These stakeholders also believe that time-variant rates could expose and reduce or eliminate the intraclass subsidies inherent in flat rates (which cause customers with a flatter load profile to subsidize the costs of customers with peakier load profiles), and they see this outcome as a positive change in cost allocation. On the matter of consumer preferences, proponents of time-variant default rates claim that customers who have experienced time-variant rates have responded favorably, although only a relatively small group of customers have chosen such rate options where they are available today. Time-variant rate proponents argue that most customers individually, all customers as a group, and society as a whole would benefit from default rates that are more reflective of price changes in the wholesale market.

The variables for designing a time-variant rate include the time intervals during which a rate is applied (ranging from two blocks per day up to hourly changes), the extent to which the rate reflects wholesale market prices, and the extent to which the actual commodity costs are hedged. Time-variant rates also might include unbundling of capacity and other charges which can significantly affect (positively or negatively) the costs paid by individual customers, especially for peak-hour power.

Proponents of time-variant default rates have different views on which type of time-variant rate would be more acceptable to customers or more appropriate as the default rate for basic residential electricity service. Additional research would be required to better understand customer preferences as between flat rate and time-variant rates, and among the different time-variant rate designs.

One time-variant potential default rate (supported by some of those who believe the default rate structure should be changed under AMI) is a Time of Use (TOU) rate. A TOU rate would vary between pre-determined fixed rates in specified periods, such as peak and off-peak, with seasonal variation. This default rate could also incorporate an overlay of critical peak pricing (CPP) or peak time rebates (PTR) to reflect the value of demand response during system peak periods. Unlike RTP that would be directly reflective of market prices, TOU rates would require advance procurement of power pursuant to approved IPA procurement plans.

Another time-variant default option would be for all residential customers taking utility supply through an AMI meter to be placed on a real-time pricing program (similar to what large commercial and industrial customers are offered today under a declaration of competitive service). The RTP rates would directly reflect changing market prices (in real time or day ahead markets), and could include the option for any customer to opt-out to a fixed price rate or a different time-variant rate. Another option might be for a baseline volume to be at a certain rate and usage above it to be at market prices. However, if the Commission were to consider any sort of default real-time pricing program, a careful analysis must be conducted to ensure that the program would comport with the intent and operation of the Illinois Power Agency Act and the Public Utilities Act. Although experience to date in both the ComEd and Ameren residential RTP programs shows savings for participating customers, the programs are voluntary and the participants are self-selected and therefore may be more inclined towards undertaking home energy management activities. RTP as currently offered in Illinois is an unhedged rate that passes on market prices to customers.[35] Some other time-variant rate options have fluctuations in prices over time, but at pre-set rates that provide more stability (which comes at the cost of a hedging premium). Proponents of such hedged time-variant rate default rates believe that customers may prefer rates that have less exposure to market price volatility because consumers presently lack sufficient knowledge and tools to facilitate home energy management.

If a time-variant default rate were put in place for residential customers, the Commission should ensure that customers have clearly defined and disseminated options and simple mechanisms to opt out of the default rate and into a flat rate. The implementation of any time-variant default rate might raise implications for supply switching rules. Some of those who oppose a time-variant default rate oppose the creation of barriers to switching to a flat rate option.

Any change in retail rate design, absent changes in consumption or procurement costs, produces a new allocation of costs among customers, and as a result, relative “winners and losers” (not necessarily equal in number). The magnitude and distribution of customer bill impacts would be functions of the particular rate design adopted and the subsequent behavioral response by customers with a wide variety of usage and demographic

[35] ComEd offers a tariffed residential real time rate program that passes through hourly PJM prices, while the Ameren-Illinois Utilities offer a similar program using day-ahead MISO procurement.

characteristics. Analysis of the ComEd pilot data may allow hypothetical testing of the effects of different rate designs on the bills of customers with various load shapes. Supporters of time-variant default rates agree that, whatever rates are approved, the ICC should consider whether a transition or phase-in approach would be appropriate to mitigate bill impacts for customers whose more costly load shapes would initially make them relative "losers."

Stakeholders agree that the Illinois Power Agency would need to adjust its procurement plans to reflect any load shifting and consumption level changes resulting from new technology or new Commission-approved rate designs, so that retail rates reflect any cost-reducing changes in supply requirements and so that retail rates properly recover total estimated supply costs, including energy, capacity, and ancillary service costs. In addition, the Commission should consider how to ensure that legislatively mandated costs, such as those for procurement of "clean coal" generation, are paid by all customers, including those taking real-time pricing options.

Consumer Education about Smart Grid

As discussed in other sections of this chapter, stakeholders agree that consumers must have a clear understanding of how they may be affected by smart grid deployment, the changes it may engender, and especially how to make good choices from among AMI-enabled options. How the educational messages are designed and conveyed (and by whom) are subjects of keen interest to stakeholders, as conveyed in the following recommendations.

Discussion

When major changes in a regulated industry occur, it is necessary and customary for a consumer education program to be part of the obligation of service providers. As with other aspects of regulated service, this effort must be optimized for both cost-effectiveness and success at achieving its goals. Unlike most other regulated utility activities, successful education of consumers about smart grid may require the cooperation and participation of non-utility entities.

Successful consumer education requires effective and coordinated communications planning and execution. Stakeholders may have unique insights into the perspectives, concerns, and needs of constituencies they represent, as well as trusted relationships that could enhance the credibility and effectiveness of consumer education efforts. Therefore, utilities should work collaboratively with stakeholders in the design of consumer education programs and in the development, targeting, and delivery of program-specific information. The Commission should consider including an ongoing process of stakeholder involvement in design and execution of consumer education programs as part of any smart grid deployment plan.

Consumer-oriented smart grid applications and programs are dependent for their success on high levels of understanding and participation by active, informed customers. These applications and programs include:

- Advanced Metering
- Demand Response
- Distribution Automation
- Energy Efficiency
- Distributed Resources
- Integration of Electric Vehicles.

Individual customers and Illinois as a whole cannot realize the full benefit of smart grid investment if consumers lack sufficient knowledge and information to make decisions that result in outcomes they perceive as successful. Effective consumer education is, therefore, essential to achieving the goals of smart grid deployment.

In general, the goal of consumer education for Commission-approved utility smart grid programs should be to provide customers with ample information to make informed choices about their participation. Consistent with this goal, program-specific consumer education and outreach efforts should be developed to support the successful implementation of any Commission-approved smart grid programs and smart grid-enabled rate structures (e.g., time of use, critical peak pricing, real time pricing, peak time rebates, direct load control).

Program-specific consumer education should be focused on the particular program and designed to achieve the following objectives:

1. Consumers should understand the nature of the program, including:

   a. A basic understanding of the technologies being used or new options available to the consumer;

   b. An understanding of any associated rate structure changes or options;

   c. The role of the utility and third parties

2. Consumers should understand the goals of the program, including potential individual and societal costs and benefits.

3. Consumers should have a clear understanding of the potential implications (benefits, costs, and risks) associated with their participation (or non-participation) in a smart grid program or rate option in light of their personal electricity needs and usage profile. Potential costs and benefits could include bill impacts and service changes, as well as identified environmental and societal impacts that have been documented. Risk implications could include price volatility, potential higher bills, and data privacy/access issues.

4. Although stakeholders do not agree about how to communicate the information, all agree that consumers should be informed of any changes in utility disconnection/reconnection practices associated with deployment of AMI.

5. Consumers should be informed of the resources and tools available to them that could be employed to estimate the potential effect of their participation in the program, to maximize the value they derive from it, and/or to minimize any potential negative impacts. These resources and tools may include rate comparison tools, energy consumption comparisons, in-home devices, and smart appliances.

6. Consumer education program messaging should be competitively neutral with respect to the customer's choice of an electricity supplier.

   The ComEd AMI pilot program currently underway has a significant educational component. Its evaluation will provide important information about what messages and methods may prove effective or ineffective in giving consumers the knowledge they need to make usage choices and to decide whether or not to participate in alternative pricing and demand response programs, given their individual circumstances and objectives. Developing the most efficacious and cost-effective consumer education program about smart grid and its consumer impacts will itself be a learning experience because we do not yet know exactly what information consumers will need or how best to convey it, and consumers needs are likely to change over time.

   Consumer education should be an element of cost-benefit analysis in any proceeding regarding approval of a smart grid deployment request.

Recovery of Smart Grid Costs

Among the most contentious issues considered by the ISSGC are those surrounding the questions of how to recover smart grid costs equitably and from whom. At the core of this contention lie the questions of what smart grid is and whether smart grid investments are different from other utility investments in ways that require special ratemaking treatment. No consensus definition has emerged that would enable an immediate and objective determination of whether a particular technology investment is a smart grid investment, or whether such an investment would differ significantly from other types of utility investment. Some stakeholders view smart grid as largely an acceleration of investments routinely undertaken as part ongoing grid modernization. Other stakeholders maintain that smart grid investments have characteristics that differentiate them from traditional utility investments that are made to expand, maintain and upgrade the electricity delivery system in ways that pose new regulatory challenges, such as:

- Smart grid technologies entail a higher level of uncertainty as to how they will function over time and how they will affect system operations, costs, and customer behavior.

- Many of the potential smart grid benefits do not accrue to the utility or through the utility to its ratepayers, or may not be sufficient to justify an extensive deployment based on an internal utility business case. In addition, there is concern among a number of stakeholders that customer, third party and societal benefits that may be used to justify investments may be difficult to predict, quantify, measure, and monetize. Further, some stakeholders have expressed concern that unilateral utility deployment will not assure the selection of technologies that will maximize potential benefits for customers, third parties or society.

- Smart grid deployment may entail high initial costs, while the anticipated customer, utility, third party and societal benefits that may justify such investments may be difficult to predict, quantify, measure and monetize, and may develop over an extended period of time.

- Depending on the utility investment plan and the choices made by individual consumers, some potential smart grid benefits may not be directly experienced by some customer groups or individuals.

- Smart grid investments by a utility are not currently mandatory unless they are needed to provide safe, adequate, and reliable service.

Whether smart grid investments are deemed to be different from ordinary utility investments or not, acceleration of smart grid spending may present financial burdens for utilities, depending on the size, scope, and scale of such investments. For ratepayers, the pace of acceleration and scope of deployment may present an additional set of risks, such as whether the predicted benefits can be captured for ratepayers in a reasonable timeframe.

Without consensus on the existence of differentiating characteristics, stakeholders were unable to come to consensus on whether non-traditional recovery of any or all smart grid costs is appropriate or necessary. (Note: Non-traditional recovery was defined for Collaborative discussion purposes as anything other than recovery of costs in the context of a general rate case.)

All stakeholders agree that regulators should carefully consider the effects of proposed smart grid cost recovery policies on the allocation of risks between utilities and customers associated with these investments. For example, under the traditional regulatory framework, in which a utility decides which investments to make, acquires and deploys capital, and subsequently seeks recovery of costs through a general rate case, the utility bears the primary risks associated with the investment. For the utility, identified risks discussed by the Collaborative include [Note: the examples listed are not intended to be legal definitions]:

- "Prudence disallowance"; for example, for having made a poor investment decision, or for retiring functional assets before they have been fully depreciated;

- "Used and useful disallowance"; for example, for installing equipment that does not provide all the benefits that were predicted;

- "Reasonableness disallowance"; for example, for excessive costs that could have been foreseen or ameliorated by utility action;

- "Regulatory lag"; for example, earnings shortfall due to lower than anticipated revenues or higher than anticipated operational costs between rate cases.

These regulatory risks provide incentive for utilities to operate efficiently and to make cost-effective investments in equipment needed to provide safe, reliable, and affordable electricity delivery services. Exposure to these risks diminishes the likelihood of a utility undertaking discretionary smart grid investments, particularly in light of certain of the characteristics of smart grid investment described above, unless certain of these risks are addressed at the outset. Moreover, exposure to such risks may encourage conservative investments that do not necessarily maximize the potential benefits for customers, third parties or society. On the other hand, the traditional utility investment and rate setting model has not been intended to capture the societal and customer-side benefits or costs of utility decision-making. Whether the trade-offs associated with smart grid justify different treatment is a significant issue for the Commission to address.

- Stakeholders also discussed potential methods of non-traditional smart grid cost recovery through various funding and cost-tracking mechanisms. Some stakeholders expressed concerns that certain cost recovery mechanisms have the effect of transferring many of the risks identified above to customers. With costs recovered in a non-traditional manner, for example in a "cost-tracking rider," some stakeholders believe that customers may be exposed to the following new risks:

- Smart grid costs billed to customers immediately or in advance, and without prior full examination and regulatory approval ;

- Diminished incentives for utility cost minimization (the flip side of regulatory lag);

- Reduced economic discipline on the utility's investment decisions because shareholder investment is not at risk;

- Costs billed to customers without engendered operational savings simultaneously reflected on monthly bills;

- Projected customer savings and other eventual benefits not materializing;

- Utility investment priorities and management focus shifted from routine Operations and Maintenance to rider-eligible investments; and

- Non-utility parties having the burden of quickly conducting complex engineering reviews in time-limited regulatory proceedings.

However, some stakeholders believe that recovery mechanisms outside of traditional rate cases can be designed in a manner that addresses these concerns.

Certain customer risks exist regardless of cost recovery method, such as costs billed to customers prior to the realization of electricity procurement and pricing benefits that depend on full implementation of future pricing programs or other investments.

Stakeholders discussed the basic arguments for smart grid cost recovery through either a non-traditional mechanism such as a cost-tracking rider or a traditional general rate case. These viewpoints can be summarized as follows:

Basic Arguments in Favor of Rider Recovery	Basic Arguments in Favor of Rate Case Recovery
1. Smart grid investments may be large and, if so, base rate treatment may strain cash flow and could deny cost recovery due to the operation of regulatory lag. 2. Smart grid investment must compete with other investment priorities when capital is limited. 3. Utilities face more risk if recovery of smart grid investment is not assured, which could raise the cost of capital faced by the utilities and ultimately paid by customers. 4. Some smart grid benefits may flow largely to customers and society, not utilities, so customers should bear some initial costs and risks. 5. Unless a smart grid investment is needed to provide safe, adequate and reliable service, it is discretionary, and absent a rider such investment may occur more slowly, if at all.	1. Base rate recovery, including incentives stemming from regulatory lag, promotes efficiency and cost-minimization and may reduce the likelihood of future stranded costs. 2. Smart grid investments are not easily differentiable; therefore, many routine technology upgrades could be presented as warranting rider treatment. 3. Base rate treatment preserves test year matching of expenses and income, which is needed to prevent excessive rates. 4. A rider allows operational and tax savings stemming from ratepayer-funded investment to be retained by the utility, potentially leading to excessive earnings and rates until the next general rate case. 5. Smart grid investment does not pass the “big, volatile, and beyond utility control” tests historically used to justify riders.

Stakeholders spent many hours discussing the cogent arguments in both columns. In the collaborative process, stakeholders were not able to reconcile these “polar” positions to reach common ground on a smart grid cost recovery framework that would address the legitimate concerns of both sides. However, the ISSGC considered a variety of approaches to smart grid cost recovery that might address some of the concerns and potentially share some of the risks outlined above. The alternatives discussed by the Collaborative included (in no particular order):

- Use of future test year rate cases;
- Use of a deferral account to accrue smart grid costs for future recovery;

- Multiple test year ratemaking period;
- Modification of rate case rules to amortize lumpy smart grid investments over long periods;
- Split cost recovery between rider and base rates;
- Costs recovered through a rider offset by projected savings; and
- Performance-based recovery of smart grid costs, with utility penalties and rewards associated with certain benchmarks such as cost savings and other benefits achievement.

Stakeholders noted that some of these alternatives might require changes in rule or law, or at least require agreement between a utility, regulators, and other stakeholders. Stakeholders discussed as well the possibility that some of them could potentially be combined as components of an overall smart grid cost recovery framework.

To that end, stakeholders discussed the overarching goal for equitable smart grid cost recovery policy: to assure that smart grid investments are undertaken when beneficial to customers, costs are disciplined, customers are protected and treated fairly, and the utility is provided a reasonable opportunity to recover its legally recoverable costs. While there is no agreement about how to achieve this outcome, stakeholders have agreed on a list of key questions that should be considered by the Commission in a thorough examination of relevant issues. For the purpose of raising these cost recovery and cost allocation issues, the questions assume that the Commission has already found that the smart grid investment is prudent, passes applicable cost-benefit test(s), and is consistent with other policies, or that the investment is needed in the provision of adequate, reliable and least cost delivery service. The following questions are organized into subject matter categories.

Distinguishing Smart Grid Investments

1. Are smart grid investments discretionary for a utility? Should the ICC determine whether any or all smart grid investments are part of a utility's obligation to provide reasonable, reliable, and least cost service? If so, what effect would such a determination have on deployment timing, pace, costs, and benefits?

2. Are smart grid investments fundamentally different from other utility investments in ways that make "non-traditional" recovery of all or a portion of the costs of these investments more appropriate than "traditional" recovery (wherein cost recovery begins after reflection of capital investments and test year O&M expenses in revenue requirements)? If so, what effect would such "non-traditional" treatment have on deployment timing, pace, costs and benefits?

3. If smart grid investments need to be differentiated for the purpose of cost recovery, how can the ICC objectively distinguish smart grid investments from other utility investments?

General Smart Grid Cost Recovery Issues

4. Should the costs (including both capital investments and O&M expenses) of all smart grid investments be recovered in the same manner? Or do differences among smart grid investments make it appropriate to employ varying cost recovery methods?

5. If all smart grid investments are not recovered identically,

    a. Should smart grid investments that enable utility operational cost savings be treated differently from those that do not?

    b. Should smart grid investments that produce immediate and measurable benefits be treated differently from those that have longer term and/or more speculative benefits?

    c. Should smart grid investments of a certain magnitude be treated differently from lesser investments?

    d. Should smart grid investments that produce substantially greater benefits through acceleration be treated differently from investment involving routine upgrade or replacement benefits?

6. Should the fact that certain smart grid investments enable some utility operational cost savings that are automatically captured through a rider mechanism (e.g., changes in uncollectibles expense), and others that are not so captured, be a factor in the selection of cost recovery mechanisms or the scope of recovery under such mechanisms?

Issues Pertaining to Risks Associated with Smart Grid Investments

7. Who should bear what risks for recovery of smart grid costs?

    a. Should the prudence of the decision to undertake the investment be determined prior to a smart grid technology deployment, absolving the utility of this risk? Or should utilities unilaterally make initial decisions regarding smart grid investments as they do for most other investments?

    b. Who should bear the risk of costs that exceed projections? To what degree?

    c. Who should bear the risk of benefits that fall short of projections? To what degree?

    d. Who should bear the risk of smart grid equipment that fails to function fully as represented?

    e. Who should bear the risk of stranded assets?

8. Would a given smart grid cost recovery method alter the risk profile of the utility in such a way as to change its cost of capital? If smart grid costs are recovered outside of a general rate case, should the cost of capital for smart grid investments be calculated separately from the overall rate of return authorized in the utility's last rate case? Is the cost of capital for the utility as a whole affected by different treatment for smart grid investments?

Cost Recovery Options under Traditional Ratemaking

9. Would use of a single year or multi-year future test period in the context of a traditional rate case be feasible and/or beneficial for smart grid investments? What would be the legal and regulatory policy challenges to such an approach?

10. Does the nature of smart grid investments make it appropriate to employ deferred cost recovery methods such as AFUDC[36] and/or CWIP[37]?

    a. If so, would changes in law and/or rules be required?

    b. Would use of such a cost recovery method result in more frequent rate case filings? Should that possibility be a factor in considering whether or not to adopt the procedure?

Alternative Cost Recovery Issues

11. If a utility requests non-traditional cost recovery, should it be required to show that it is financially unable to make a proposed smart grid investment absent such treatment?

12. Would it be feasible, practical, possible and appropriate to split recovery of smart grid costs using an overall formula, such as X% in base rates and Y% in a cost-tracking rider, or $X through one method and amounts above $X through another method? What would be the implications of such an approach on findings of prudency, just and reasonable rates, reasonable expenses and other issues?

13. Assuming a non-traditional cost recovery method is proposed, are performance-based rate mechanisms (PBR) potentially appropriate for smart grid investment; i.e., can they be designed to align the interests of utilities and customers?

    a. How would development and implementation of such a plan be affected by Section 9-244 of the Public Utilities Act?

    b. Should performance-based mechanisms be based on the cost/benefit categories proposed as justification for the investment?

    c. What process should be used to set performance benchmarks?

[36] Allowance for Funds Used During Construction
[37] Construction Work In Progress

d. Should continuance of non-traditional cost recovery be tied to achievement of benefits or meeting certain benchmarks?

e. What standards or metrics would be appropriate and productive to employ? For example:

   i. operational cost savings

   ii. capital budget cost containment

   iii. deployment milestones

   iv. measurable customer usage reductions, as measured by effect on customer bills

   v. measurable customer peak reductions, as measured by effect on customer bills

   vi. participation rates in smart grid programs

   vii. measurable wholesale market effects

   viii. measurable retail supply price effects for different customer groups in Illinois

   ix. measurable service quality indicators

   x. measurable effect on projected societal benefits (if any)

f. Should a performance-based plan be symmetrical; i.e., should it penalize the utility if benchmarks are not met, and provide the utility an opportunity for higher earnings if benchmarks are exceeded? For how long should penalties and rewards accrue?

Implementation Issues

14. What would be the process and scope of ongoing regulatory review of performance, costs and benefits associated with any smart grid investment subject to non-traditional recovery?

15. What regulatory oversight measures can assure that the utility gives priority to reliability and adequate service investments, other non-discretionary system upgrades, and general operations and maintenance, if the cost recovery mechanism makes smart grid investments more economically attractive to the utility?

16. If non-traditional cost recovery mechanisms are employed to recover the “smart grid” portion of utility infrastructure investment, should these costs be identified separately on customer bills?

17. Assuming a cost-tracking mechanism is employed, should any rider recovery of smart grid investments be offset by:

    g. Business-as-usual amounts already recovered in base rates for similar equipment?

    h. Projected net O&M savings from the investments?

    i. A percentage of each investment, to be addressed in the next rate case?

18. What kind of limits, if any, should be placed on smart grid cost recovery amounts to protect ratepayers from experiencing high net increases in their individual electric bills?

19. What new burdens would a non-traditional cost recovery regime place on ICC Staff, intervenors, and utilities? What would be the magnitude of any such resource burdens? Assuming a non-traditional cost recovery method is proposed, how could regulatory proceedings involving smart grid investments be structured and timed so as to give parties an opportunity to fully address these issues and provide the commission with an optimal record on which to base its order?

20. What performance metrics, if any, should be established to track utility and consumer benefits?

Cost Allocation Issues

In addition to determining the manner and means for recovering smart grid costs, the ICC ultimately must also decide how to allocate costs among customer classes (interclass cost allocation), and among customers within classes (intraclass rate design). Also, because some beneficiaries of smart grid applications may not be jurisdictional customers, some stakeholders argue that cost allocation must have a wider scope. Cost causation has been a primary driver of past regulatory cost allocation policies for jurisdictional customers. The following general questions with regard to cost allocation should not be considered exhaustive.

21. Should smart grid cost allocation be based on the same principles of cost causation used for other utility costs?

22. Should the Commission use benefits received as a surrogate for costs caused in allocating smart grid costs to customers? Is allocating a cost to those benefited by it different from current determinations of cost causation?

23. Are there any changes in law required to allocate costs on principles other than cost causation, if the Commission were to find that appropriate?

24. If the Commission were to allocate costs based on benefits received, should smart grid costs be allocated for recovery based only on the benefits quantified to justify the investment, or should all projected smart grid benefits be included? If all benefits are included, how could costs associated with non-quantifiable benefits be allocated to ensure that recovery levels are commensurate with benefits?

25. Should costs be allocated to customers who do not benefit from some or all utility smart grid investment, or who have taken measures at their own cost to achieve the same or similar benefits?

26. Can the Commission allocate any costs to non-jurisdictional entities? How would such allocation affect cost recovery?

27. If costs are allocated to non-jurisdictional entities, what measures can ensure that any revenues received by the utility from non-jurisdictional entities are appropriate in level and properly reflected in jurisdictional customer rates? Should the ICC require that utilities file tariffs specifying fees for non-jurisdictional parties' use of or access to utility infrastructure?

Statutory Energy Goals and Smart Grid

Foundational policy #6 in the ICC's Order authorizing the Collaborative tasks the Collaborative with consideration of the "effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation."

Background

Illinois is one of 29 states with a legislated goal of procuring increasing amounts of renewable electricity output to displace fossil-fueled generation, and one of 23 states with a statutory requirement for Energy Efficiency (EE) investment. Illinois is also one of only several states that have enacted specific demand response (DR) standards for utility programs.

The Illinois "Renewable Portfolio Standard" (RPS) requires utilities and other electricity suppliers to acquire and retire Renewable Energy Credits (RECs) equal to about 5% of their historical or current megawatt-hour sales in 2010, with amounts increasing incrementally in subsequent years until reaching 25% in 2025. The actual amount of renewable energy planned for procurement in a year is subject to a cap triggered if and when the aggregate net increase in the consumer price per kilowatt-hour due to the RPS is projected to be greater than approximately 2%. The Illinois RPS requires most RECs to be derived from wind generation and a portion eventually derived from solar power. The acquisition methods prescribed in the statute assure that most RPS resources will be purchased through the Illinois Power Agency procurement process, which may employ both short- and long-term strategies to acquire in-state and regional resources, in accordance with annual plans approved by the Commission.

Responsibility for energy efficiency program implementation is shared between the utility and the state's Department of Commerce and Economic Opportunity. EE program goals for 2010 are set by statute at 0.6% and annually increase incrementally to 2.0% in 2015. Utility demand response programs are required to achieve a 0.1% annual peak demand reduction for small business and residential customers taking utility electricity supply, so that the aggregate peak reduction compared to what would have otherwise occurred totals at least 1% over a ten year period ending in 2018. Like RPS, combined costs of EE and DR programs are also subject to an approximate 2% cost cap. The Commission is to report to the General Assembly in 2011 if operation of the cost caps unduly constrains acquisition of renewable energy, energy efficiency and demand response resources.

Assuming that statutory goals are met as scheduled, renewable energy procurement in Illinois would be anticipated to exceed 7 million megawatt-hours in 2011, and increase to greater than 35 million megawatt-hours in 2025. At an average capacity factor of 30%, more than 3,000 megawatts of wind power capacity (not necessarily located in Illinois) would be needed to meet the statutory wind standard in 2014 and 10,000 megawatts in 2025. Compliance with the solar standard would eventually require more than 1,500 megawatts of solar capacity, equivalent to the output of more than 500,000 typical photovoltaic rooftop installations.

Annual incremental reductions in energy usage due to statutory EE standards would exceed 1 million megawatt-hours in 2011 and 2.5 million megawatt-hours by 2015. Statutory utility DR programs would achieve a total peak demand reduction of over 150 megawatts by 2018.

Discussion

The statutory RPS, EE and DR standards were set prior to consideration of smart grid deployment and compliance with them must occur whether or not smart grid deployments occur in Illinois. Furthermore, funding for achieving these goals is provided through statutory provisions operating separately from the Commission's ratemaking process. Accordingly, the Collaborative has acknowledged in the Cost-Benefit Framework chapter of this Report that costs and benefits from statutorily required RPS, EE and DR programs must be accounted for separately from the costs and benefits of proposed smart grid investments.

From this perspective, Illinois' mandated energy goals may not affect smart grid planning and implementation at all. However, the cost caps for RPS, EE, and DR may serve to limit the eventual size and scope of programs and constrain achievement of the statutory energy goals as they become larger percentages of electricity usage over time. Achievement of certain of these energy goals within the cost caps may eventually be facilitated by, if not dependent on, smart grid functionalities.

For example, smart grid applications could ease the integration of small scale solar and other household or locally-based distributed renewable generation. Energy efficiency improvements could also be enhanced by certain smart grid functionalities. Traditional energy efficiency programs are primarily targeted at reducing the electricity usage of appliances, motors, lighting, and HVAC systems by replacing them with more efficient units and by sealing building envelopes; but there are also potential efficiency programs that are targeted to household consumption behavior, such as billing enhancement programs offering usage comparisons with other households. Smart grid investments, to the extent that they are directed to providing more granular usage and pricing information to customers through in-home devices or linkages to appliances, may contribute to overall improvement in energy efficiency. Similarly, a smart metering program could create the opportunity for targeted pricing or incentive programs to reduce peak demand, in addition to the residential direct load control programs used today to meet the DR standards. While not supplanting statutorily mandated utility programs, smart grid technology development and deployment could contribute towards meeting or even exceeding existing statutory objectives.

In short, the interplay between smart grid development and achievement of Illinois' statutory energy goals suggests that there may be some "effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation." However, the degree and timing of any such effect is not known at this time. The potential value of smart grid technologies that enable enhanced customer interfacing programs is currently under study in Illinois, and the ability of these programs to contribute to the state's efficiency and demand response goals in the future is a question for consideration by the Commission and the General Assembly as the pace and scope of smart grid technology development and deployment evolves.

Technical Characteristics and Requirements

Introduction

This section introduces the Smart Grid Technical Characteristics and Requirements section of the Report.

Purpose

This section of the Report captures the recommendations of the Illinois Statewide Smart Grid Collaborative (ISSGC) regarding the technical characteristics and requirements for smart grid. The purposes of this section of the Report are to:

- Provide a list of characteristics and technical requirements that must be included in each utility's smart grid filing to receive consideration from the Commission
- Provide a tutorial to readers of this Report on the important technical issues associated with the development of smart grid projects in general and specific applications in particular.
- Provide technical guidance on the following foundational policies identified in the ICC Order:
    - Foundational Policy 2 – Interoperability, open architecture, non-discriminatory access
    - Foundational Policy 3 -- Uniform standards
    - Foundational Policy 8 -- Access by electricity market participants to smart grid functionalities
    - Foundational Policy 9 -- Data collection, storage, management, security, and availability to third parties
    - Foundational Policy 10 -- Standards for interconnection of third party equipment
    - Foundational Policy 13 -- Open architecture and inter-operability standards for technological connectivity to the Regional Transmission Operator (RTO) or Independent System Operator (ISO)

Scope

These technical requirements and recommendations were developed in response to the Order of the Illinois Commerce Commission.

These technical requirements and recommendations were developed in the context of the smart grid applications identified in the Smart Grid Applications chapter of this Report. Other possible smart grid applications are not discussed here.

Some of these requirements and recommendations follow the principle that, in general, all smart grid applications should be available to all customers. However, it is important to note that providing the technical capability does not guarantee that the capability will be used by the customer.

Interoperability: A Primary Goal

Interoperability between the components of the smart grid is a primary goal and underlying theme of these technical requirements and recommendations.

The Collaborative notes that the Energy Independence and Security Act (EISA) of 2007 directed the National Institute of Standards and Technology (NIST) to create an Interoperability Framework of standards for the smart grid, and NIST in turn created the national Smart Grid Interoperability Panel (SGIP) with this goal in mind. The NIST Interoperability Framework provides the following definition of interoperability, based on definitions from the U.S. Department of Energy Smart Grid Investment Grant Program Funding Opportunity Announcement and the Department of Energy (DOE) GridWise Architecture Council Interoperability White Paper:

> *"The capability of two or more networks, systems, devices, applications, or components to exchange and readily use information—securely, effectively, and with little or no inconvenience to the user. The Smart Grid will be a system of interoperable systems. That is, different systems will be able to exchange meaningful, actionable information. The systems will share a common meaning of the exchanged information, and this information will elicit agreed-upon types of response. The reliability, fidelity, and security of information exchanges between and among Smart Grid systems must achieve requisite performance levels."*

The Collaborative agrees that interoperability between components of the smart grid is critical for the following reasons:

- It increases the technical options available to utilities and helps utilities to avoid "lock-in" with a particular technology or supplier.
- It enables ease of movement of customers, products, and services between utilities and regulatory jurisdictions, and therefore increases customer choice.
- It increases healthy competition in the marketplace while also increasing the overall market available to suppliers, driving down the overall costs of the implementation of the smart grid.

All the smart grid design issues identified by the Collaborative in this chapter either encourage greater interoperability, or are enabled by greater interoperability. In particular, the issues of Technical Maturity and Risk, Openness and Standardization, Manageability, and Upgradeability are very closely correlated with interoperability. For this reason, interoperability is identified as a primary goal of these technical requirements.

National Standards Applying to Smart Grid Proposals

There are a variety of proprietary, industry, national and international standards that are available and applicable to smart grid applications. As noted in this Report, the Collaborative recommends the use of open technologies over proprietary ones, and recommends the use of officially recognized and standardized technologies over those that are not. Some of these are listed for information purposes in the Bibliography.

However, the requirements and recommendations described here do not specify the use of any particular technology, standard or best practice, for the following reasons:

- The scope of the smart grid exceeds local or state boundaries. To identify standards that only apply within Illinois would potentially create barriers to interoperability between utilities in different states. Specifying an Illinois-only standards framework could possibly limit the products and services available to consumers within Illinois
- The U.S. Federal government has begun the process of establishing nationwide smart grid standards by directing the National Institute for Standards and Technology (NIST) to develop an interoperability framework. The first version of this national framework has been published. Therefore, any attempt to require Illinois utilities to use particular technologies could conflict with the national efforts, which is not desirable

As noted elsewhere in this Report, Illinois utilities shall be required to explain their choice of any standards or technologies that are not recommended by the NIST Smart Grid Interoperability Framework.

TERMINOLOGY

The following convention respecting recommended Commission actions is used in this Technical Requirements section of the Report:

- Use of the word “should” implies the item should be a recommendation and should be optional
- Use of the word “shall” or “must” implies the item should be a requirement and is not optional. There are relatively few actual requirements.

RECOMMENDED FILING REQUIREMENTS

The Collaborative recommends that the Commission require utilities to provide the following information on smart grid investments:

- A list of smart grid applications included in the smart grid investment
- A description of how the utility plans to address, for each application, each of the design issues listed in the Design Requirements and Recommendations section of this chapter. [Note: the potential impact of each design issue on each application is summarized in tables at the end of this chapter.]

- Additional specific information per application as appropriate, as discussed in the application-specific sections following the Design Requirements and Recommendations section of this chapter. These sections identify specific technical issues, recommendations and requirements for each application.

It should be noted that utilities are free to discuss any applications or design issues that are not listed here.

If a utility chooses to implement an application not identified in this document, the utility shall (as for other applications) discuss in its filings the same design issues listed in the Design Requirements and Recommendations section.

Beyond any other requirements listed here, utilities shall be responsible for ensuring their technological solution is capable of meeting the policies required by regulation.

Design Issue Requirements

1. For each application and design issue identified here, the utility shall answer the following questions:
   - How does the smart grid investment address this design issue for this application?
   - Does this design issue present a challenge for this application?
     - If not, why not?
     - If so, how is the challenge being addressed?
   - What is the basis behind the technology selections as they relate to cost and benefits?
   - Under what conditions will the requirements and the importance of this issue vary?
   - Additional specific information for each issue as described in that section
2. The utility shall identify the criteria they used to evaluate technical maturity and risk
3. The utility shall explain what measures will be put in place to make it possible for the functions of the smart grid components to continue to be maintained and supported
4. The utility shall identify which standards are used in their solutions
5. The utility shall explain why any of the following types of standards, technologies or specifications are used:
   - Those that are proprietary or non-standard
   - Those requiring royalty fees
   - Those not listed in the NIST Interoperability Framework
6. The utility shall explain what level of interoperability is required for the application, and the level of standard therefore used, for example:
   - With multiple vendors' equipment

- With other utilities
- With other industries
- With other countries

7. The utility shall describe their plan to ensure that there are published specifications for the applicable customer end devices and third parties to communicate with the utility
8. The utility shall identify for each application:
   - How the data are protected from eavesdropping (confidentiality)?
   - How the source and destination of the data are verified (authentication)?
   - How the data are prevented from modification or loss (integrity)?
   - Which NERC Critical Infrastructure Protection (CIP) requirements apply to this application?
   - Which NIST security requirements apply to this application?

   Note that this requirement does not ask that the utility identify security vulnerabilities. Only the general techniques, standards and methods used by the utility need to be described
9. The utility shall identify how the performance and health of the smart grid system is will be maintained
10. The utility shall describe the degree to which the system has been designed with sufficient capabilities and resources to adapt to future conditions, in particular those areas known to be barriers to expansion, such as disk space, memory space, bandwidth, processing power, tools, etc.
11. The utility shall explain how the system will integrate with existing systems, if applicable, for each application
12. The utility shall explain why any applications cannot be made available to all customers.
13. The utility shall identify which applications and functions are critical during power failures, and explain the design choices made to ensure they continue to operate.

Application-Specific Requirements

In addition to the general requirements listed above, the Collaborative has identified a number of requirements that are specific to each particular smart grid application. These application-specific requirements are listed in the "Technical Requirements" subsections for each application.

Design Requirements and Recommendations

This section describes the technical requirements and recommendations arising from smart grid design issues that apply to all applications.

Overview of Design Issues

The Collaborative has identified the following minimum list of design issues associated with implementing smart grid applications:

- Capacity, including the factors
  - Latency
  - Data Volume
  - Event Rate
- Technical Maturity and Risk
- Openness and Standardization
- Security
- Manageability
- Upgradeability
- Scalability
- Reliability
- Interactivity

This list is intended to be comprehensive, but utilities are free to discuss any additional issues they consider significant.

For each application and design issue, the utility shall answer the following questions:

- How does the smart grid investment address this design issue for this application?
- Does this design issue present a challenge for this application?
  - If not, why not?
  - If so, how is the challenge being addressed?
- What is the basis of the technology selections as they relate to cost and benefits?
- Under what conditions will the requirements and the importance of this issue vary?
- Additional specific information for each issue as described in that section.

Capacity

Description of Issue

Capacity in this context is the ability of a communications link to carry data, also known as bandwidth. The requirements for capacity are primarily determined by three factors, as shown in the following table.

Factor	Definition
Latency	The maximum time that a single message can travel in one direction and still successfully implement the application. The variability of latency may be a technical challenge.
Data Volume	The typical size of messages required by the application, or the total amount of data (measured within an appropriate length of time) required to operate it. Ideally, high-volume traffic such as firmware updates should not affect the normal operation of the system. This factor is related to Scalability.
Event Rate	The rate at which messages (polls, requests, queries, responses, reports, files, etc.) must be transmitted in order for successful application operation.

Additional Information Supplied

The utility should characterize latency in terms of the following general ranges:

- Real-time = <1 second
- Near real-time = 1-5 seconds
- Non-real-time = 5-30 seconds
- Human response time = 30 seconds-1 minute
- Informational = hours

Technical Requirements

- None identified.

Technical Maturity and Risk

Description of Issue

The degree to which the solution to the application is well-understood by those who must implement it within the industry. This is the level of certainty that the technology will meet the requirements of the application.

Technology may be in various states:

- Currently only academic research
- Becoming obsolete
- Used only in pilot projects
- Considered standard practice
- Considered best practice

Note that greater maturity is not always better. The technology may be so mature that it is obsolete and, therefore, more risky to implement.

There is a concern that many new technologies may not have the same life span as older technologies and may not be supported for the length of time required by the utility. In this case, the technology may be mature, but not supported. There are a variety of methods that could be used to address this concern, for example: evolution paths, alternate choices, standard interfaces, swappable equipment, stored replacement parts, and/or service level agreements.

Additional Information Supplied

None beyond that listed below.

Technical Requirements

- The utility shall identify the criteria they used to evaluate technical maturity
- The utility shall explain what measures will be put in place to make it possible for the functions of the smart grid components to continue to be maintained and supported

Openness and Standardization

Description of Issue

Openness is the degree to which it must be easy to obtain the technology used to implement the application. Openness reduces barriers for new vendors to enter the market and encourages choice and competition. Open technologies have few or no royalties or license fees.

Standardization is the degree to which the technologies used to implement the application must be recognized by official organizations and the user community.

It is important that smart grid components:

- Share a standardized information model across the system
- Separate the information model from how data are transmitted so that new technologies can be used in the future.

Ideally, all smart grid technologies would be open standard technologies.

There are some conditions under which it may be necessary to use proprietary technologies. In those cases, it is useful to identify which system interfaces will be open and which are proprietary.

Additional Information Supplied

The utility should explain why the following are used, although one is not necessarily preferable over the other:

- Licensed vs. unlicensed frequencies
- Public vs. private networks

Technical Requirements

- The utility shall identify which standards are used in their solutions
- The utility shall explain why any of the following types of standards, technologies or specifications are used:
  - Those that are proprietary or non-standard
  - Those requiring royalty fees
  - Those not listed in the NIST Interoperability Framework
- The utility shall explain what level of interoperability is required for the application, and the level of standard therefore used, for example:
  - With multiple vendors' equipment
  - With other utilities
  - With other industries
  - With other countries

The utility shall describe their plan to ensure that there are published specifications for the applicable customer end devices and third parties to communicate with the utility.

Security

Description of Issue

The degree to which the data, equipment, persons and organizations involved in the application must be protected from attack, whether physical or electronic.

Ideally any transaction should be secured that involves personal consumer information, power system protection, or corporate business plans.

Ideally any transaction should be secured if it crosses the boundaries of organizations or crosses smart grid conceptual domains.

Additional Information Supplied

None beyond that listed below.

Technical Requirements

The utility shall identify for each application:

- How the data is protected from eavesdropping (confidentiality)?
- How the source and destination of the data is verified (authentication)?
- How the data is prevented from modification or loss (integrity), including intentional interference or blocking of the signal?
- Which NERC CIP requirements apply to this application?
- Which NIST security requirements apply to this application?

Note that this requirement does not ask that the utility identify security vulnerabilities. Only the general techniques, standards and methods used by the utility need to be described.

Manageability

Description of Issue

This is the degree to which devices, systems, and data must be configured, synchronized, tracked, diagnosed and/or maintained in order to implement the application. It includes the ability to measure the health and the performance of the system.

Ideally all these tasks can be performed remotely on field devices in a smart grid system.

Manageability includes the degree to which a system is "plug and play". This may include whether devices:

- Automatically detect when components are added or removed.
- Describe the data that they can provide

Note that "plug and play" is not always desirable in all equipment. It may be required for customer equipment, for example, but not within a substation.

Manageability is inversely proportional to the number of items (devices, systems or data) that must be managed, the complexity of the application, and the diversity of ways the application can operate.

Additional Information Supplied

None.

Technical Requirements

The utility shall identify how the performance and health of the smart grid system will be maintained.

Upgradeability

Description of Issue

This is the degree to which the devices and systems that implement the application can be changed to adapt to future conditions.

Ideally, except for hardware, field devices should be upgradable without sending personnel to the site.

Upgradeability is critical to minimize the risk of stranded assets. It is related to Technical Maturity and Risk. It indicates how much an upgrade of the system would cost, and whether it is possible at all.

Upgradeability includes the degree to which the system remains backward-compatible with older systems, and to which it can accommodate alternate technologies.

Additional Information Supplied

The utility should identify how the following may be upgraded or changed:

- Hardware
- Electronically stored information such as firmware, configuration parameters, algorithms, or security credentials
- Connectivity
- Communications technology.

The utility should discuss any expected future applications that will leverage the new system.

Technical Requirements

The utility shall explain how the system integrates with existing systems, if applicable, for each application.

The utility shall describe the degree to which the system has been designed with sufficient capabilities and resources to adapt to future conditions, in particular those areas known to be barriers to expansion, such as disk space, memory space, bandwidth, processing power, and tools.

Scalability

Description of Issue

This is the degree to which the system implementing this application will permit future expansion.

Ideally a smart grid deployment would have no fixed limits on growth. Rather, it would consist of modular components that could be added over time to accommodate growth.

Additional Information Supplied

The utility should identify:

- Which components are critical to expanding their smart grid system
- If a pilot program is planned, how it could be expanded
- What tools their chosen technologies provide for scaling.

Technical Requirements

- The utility shall explain why any application cannot be made available to all customers.

Reliability

Description of Issue

The degree to which the combined power and communications system can automatically recover from power, communications and component failures while implementing this application, in order to minimize the impact to the customer and the system.

Ideally any smart grid system

  - Automatically re-routes communications messages
  - Coordinates recovery over a wide geographical area

- Limits the area of impact of failures
- As a default state, provides a known, safe and recoverable condition whenever power, communications, or control is lost.

Reliability in this case also includes the availability of communications links in the face of failures or high traffic conditions, and ensuring that critical messages are received within their latency requirements. Some solutions to this issue may involve redundant message paths, and may be a consideration in the type of network chosen.

Additional Information Supplied

None.

Technical Requirements

The utility shall identify which applications and functions are critical during power failures, and explain the design choices made to ensure they continue to operate.

Interactivity with Customers

Description of Issue

This is the degree to which the system implementing the application helps the power system and its users react to each others' needs.

Ideally any smart grid system should be designed to:

- Minimize the effort required by customers to participate
- Permit exceptions and special cases for medical and other reasons.

Additional Information Supplied

The utility should explain how their system:

- Encourages consumer awareness and control of energy
- Increases awareness of grid reliability
- Enables communication of information between the utility and consumer
- Encourages participation in energy markets.

Technical Requirements

- None identified.

AMI Requirements and Recommendations

This section describes the technical requirements and recommendations for each Advanced Metering Infrastructure (AMI) application.

Core AMI Functionality

Description of Application

This application allows the utility to collect usage data from customers more frequently and supports time differentiated interval measurement. These new measurement capabilities allow for new rate structures and can support increased customer awareness of their energy usage. Core AMI functionality includes theft and tamper detection.

Issues

- Billing could be either paper or electronic
- Net metering is a separate function covered under "Customer Distributed Resource Interconnection"

Recommendations

- Customer usage should be recorded at least every hour and reported (not necessarily validated) daily
- A utility should be able to complete an on-demand read of a customer's meter within approximately within one minute under normal conditions. This read should include:
- The "odometer" read – the cumulative usage as of the moment of the request (the same value that would be read from the panel of the meter)
- Every fully recorded interval since the previous day's report
- The utility should be able to verify within one minute under normal conditions that any particular meter is functioning and communicating
- The technologies deployed should be capable of covering the entire current customer base plus expected growth
- All meter form factors should be supported across the service territory
- Theft or tampering information should be available to the utility within a day of the meter reporting the event
- The meter management system should have an accurate record of the location of each meter for purposes of detecting theft and tampering. The utility should explain how they intend to resolve discrepancies in their meter management databases
- The AMI system should verify power status and connectivity of each meter at least once per day

Technical Requirements

- The system shall permit a complete validated read of all meters twelve times a year within the normal monthly billing windows. It is expected that most technologies will be able to perform much better than this.
- Customer usage and billing data shall be kept confidential
- The system shall retain usage data for the time required by regulations

Remote Connect/Disconnect

Description of Application

The utility can remotely open or close the AMI disconnect switch by sending a signal to the meter for purposes of customer requested service connection and disconnection or for disconnection for non-payment and reconnection after payment is received.

Issues

- The ability to remotely disconnect on the request of the customer or emergency workers when a fire or other emergency condition is important
- This technology currently only applies to <=240V single-phase self-contained meters. It would be desirable to perform remote connect/disconnect with other types of meters if possible

Recommendations

- The metering system should be able to process connection and disconnection requests either immediately or in batch processing
- The system should be able to connect or disconnect service within 15 minutes of the request to the system. The technology is typically able to perform much more quickly than this, perhaps within 1 minute
- The utility should have the ability to notify the customer of an impending reconnection action before performing the reconnection with the AMI service switch.

Technical Requirements

- The utility shall have a process defined for authenticating the identity of any customer requesting a service connection or disconnection
- The electronic command to connect or disconnect shall be confidential, authenticated and checked for integrity
- The meter shall confirm the connect or disconnect and report it with a timestamp to the meter data management system within the regular reporting interval
- The system shall provide the necessary technical capabilities to meet the remote connect/disconnect requirements set forth by applicable laws and regulations

Outage Management Support

Description of Application

AMI Meters can report power outage and power restoration to the utility allowing the utility to improve its ability to determine the scope and location of an outage, to improve outage response, and to verify that all affected customers are restored.

Issues

- Note that integration of an Outage Management System (OMS) with metering data is a large topic, and that it ought to be discussed in detail by the utility in general, not just as it applies to AMI
- Note that both utilities already have sophisticated OMSs implemented. Many of the other applications assume an existing OMS. OMS is a major smart grid application
- The AMI system is typically not the primary means of detecting widespread outages. AMI provides supplemental information to OMS that provides the most value in verifying that power has been successfully restored, or in detecting isolated outages

Recommendations

- Every meter should have the capability to report power on/off events. However, there is a design issue regarding the volume of traffic that can be generated if every meter has this feature enabled. The utility should discuss how they plan to manage this traffic, for example, by designating "bellwether" meters
- The power on/off messages from meters should be time-stamped. It should be noted that there is a technical issue regarding whether the meter or the head-end of the metering system does the time stamping. In general, time-stamping at the meter is preferable but it is not always possible
- The power on/off messages from meters should be processed for outage management within 1 minute of transmission by the meter. Operators may be notified of the outage sometime later after analysis has occurred
- The combined AMI and OMS system should be designed to filter events to avoid being overwhelmed by large-scale outages
- The OMS and AMI should permit operators to manually "ping" a subset of meters to determine power status and connectivity

Technical Requirements

- None identified

Power Quality/Voltage Monitoring at Meter

Description of Application

AMI Meter data can provide the utility with an extensive view of voltage levels throughout the distribution system. AMI Meters may also provide other measurements that allow the utility to evaluate system harmonics. The ability to achieve the benefits for this application largely depend on the capability of the meter to perform measurements that are not normally associated with traditional metering functionality and the network capacity to transport the additional data.

Issues

- When performing voltage measurements, there are a variety of methods that can be used to calculate and report the voltage (e.g., peak, RMS, out-of-band). The applications of power quality monitoring are not well-defined at this time. The accuracy of the voltage measurement is also a factor to consider.
- There is a cost/benefit tradeoff concerning how many meters have the capability to report power quality and voltage, and whether meters need to be physically exchanged to enable this capability.

Recommendations

- The utility should explain their reasoning for putting power quality programs in place
- The utility should explain which method of voltage measurement and reporting they are choosing and why

Technical Requirements

- None identified

Customer Prepayment Utilizing AMI

Description of Application

Customers may have the option to pre-pay for their electric service providing the customer with greater understanding of their energy usage and ability to better budget their energy costs. Prepayment customers typically conserve energy when provided with energy and cost data.

Issues

- Many stakeholders view Customer Prepayment as controversial. Concerns over Customer Prepayment are described in the Consumer Policy Issues chapter of the Report. There is no current expectation that the utility would be required to take payment from customers at the customer premises.

Recommendations

- The prepayment control system should permit multiple flexible options for:
    - Signals to the customer regarding amount of usage left
    - Configurable delay of disconnection after prepayment has expired
    - Immediate restoration of service (within 15 minutes) after validation that payment has been made.
- Validation of payment should occur within a reasonable amount of time
- The meter should confirm the connection or disconnection of service and report it with a timestamp to the meter data management system within the regular reporting interval

Technical Requirements

- If the utility implements prepayment, the prepayment control system shall have the capability to perform the following tasks if specified by policy and regulations:
    - Prevention of disconnection due to seasonal rules
    - Prevention of disconnection for medical reasons
    - Prevention of disconnection at the request of a third-party (e.g., an alternative retail electric supplier)
    - Validation of payment and reconnection of service within periods defined by applicable laws and regulations

Customer-Oriented Applications Requirements and Recommendations

This section describes the technical issues, requirements and recommendations for each customer-oriented application.

In-Premises Devices for Energy Usage Data

Description of Application

Customers can install devices that can receive and display energy usage and decrease their energy consumption. AMI meters can be used to communicate energy data to in premise devices using a home area network (HAN) and provide better data, but AMI meters are not explicitly necessary to perform this application.

Issues

- Note that sending pricing information (as opposed to usage information) to the customer's device is discussed in the section on Demand Response applications
- There are at least two possible designs.
  - Raw data sent directly from the meter to the in-home device. This data could be the current value or historical information
  - Validated usage data, possibly a historical record, sent from the Meter Data Management System (MDMS) or other utility back-office system to the in-home device through the meter
- There is a concern about whether security is established only between customer devices and the meter, or between customer devices and the utility back-office systems

Recommendations

- The utility should explain which of the major choices they are implementing, e.g., transmitting raw usage data or validated usage data
- The customer device should not require extensive configuration by the customer. Ideally, there would be no configuration by the customer at all

Technical Requirements

- The utility shall explain whether security is established end-to-end between customer devices and the back-office systems, and if so, how.
- The customer device and the utility energy services interface shall be mutually authenticated.
- The utility systems shall be able to detect when a customer device has been connected and when it has been successfully authenticated and configured; information respecting customers' ownership and use of such devices shall be treated as confidential customer information.
- Customer usage data transmitted to the customer device shall be confidential, authenticated, and checked for integrity (the data sent is the same as the data received).

- In order to fulfill its duty to ensure security, the utility shall specify the interface requirements for a customer device, including security considerations. The utility side of this interface shall conform to open standards and best security practices.

Customer Web Portal for Energy and Cost Data

Description of Application

Customers can view historical energy usage and billing data provided by their electric supplier on the internet. Information viewed on the internet would not be real time, but would allow for more descriptive views and comparisons of a customer's energy usage.

Issues

- Usage information provided to customers through the web portal will be very accurate when gathered using advanced metering. However, the complexity of the billing operation may make it difficult to provide cost information from the web portal that is as accurate as the customer bill. It may be necessary for costs to be estimated based on usage only rather than on any non-usage based charges that might be part of the bill.
  - If such constraints are placed on the cost information, the web portal should notify customers of the limitations of its accuracy
- In addition to usage information, web portal may provide various software features for suggesting how customers can reduce their electrical bill. However, such features are not a requirement
- This application may be performed without the need for an AMI system. It can be performed through third-party communications networks
- It should be noted that the technology has the capability to provide pricing information in near real-time, although this is not a requirement
- Standards are still evolving for providing this data to third parties

Recommendations

- The utility should investigate open standards for providing this data to third parties. The utility should explain whether they are partnering with such third parties and whether they are using open standards.
- The customer should be provided with usage and cost information from at least the previous day if not more recently.

Technical Requirements

- Customer usage data transmitted to the customer through the web portal shall be confidential, authenticated, and checked for integrity.

Outage Notification to Customer

Description of Application

The utility can inform customers through automated emails, text messages and phone calls of existing outages and estimated restoration times. Customers receiving this information can make better decisions on how to respond to the outages.

Issues

- There are a number of ways customers could be notified, and a variety of times at which a customer may wish to be notified
- Latency is not a critical issue
- A possible additional feature would be to send estimated restoration times, with the recognition that the information may not be available
- A possible additional feature would be to permit a query of the outage status by the customer

Recommendations

- The system should offer choices on notification cycle and methodologies
- The system should be capable of scaling to a large volume of customers
- There should be notification of outage restoration in addition to outage occurrence
- The system should be flexible enough to add additional information to the notification in the future

Technical Requirements

- None identified

Third Party or Government Use of Customer Data

Description of Application

The utility passes usage data about customers to authorized third parties. The data may or may not be anonymous depending on the third party and purpose for providing the data. Customers will choose which third parties they wish to share their data with.

Issues

- Elsewhere in this Report, the Collaborative has recommended that the government should have no special rights or access to customer data beyond that required by law, and that a customer must authorize release of their data to third parties.
- It is difficult to make technical security requirements for this application because they are driven by policy.
- Because the policy requirements of this application are not yet known, the technical risk of this application is high.

Recommendations

- There should be a standard set of interfaces for this data defined so a different interface is not required for each third party, at higher cost.

Technical Requirements

- The system must be capable of enforcing the security policy defined by laws and regulations regarding third-party access.
- The default for third-party access must be that all access to customer usage data is restricted.
- The system shall be able to provide customer usage reports for the length of time that are at least equal to data retention requirements set out in applicable laws and regulations.

Demand Response Applications Requirements and Recommendations

This section describes the technical issues, requirements and recommendations for each demand response application.

Pricing Information to In-Premises Devices

Description of Application

Demand response generated by price signals leaves the customer in control of how they wish to manage their usage during periods of high cost energy. Price based demand response requires the customer to have more advanced devices if they wish to automate the response.

Issues

- There is a technical issue regarding how the customer may receive the pricing data for display in the home; if it is performed through the AMI network it may require extensive integration work by the utility. It may also be provided through the Internet. The utility should be very clear about where this information is acquired and how it is provided to the customer. They should also be clear in communications to the customer at what level of accuracy this pricing information is provided.

- The scaling level of these programs will vary depending on voluntary customer participation, although it is expected to increase over time.
- Depending on the technology used, it may be possible to broadcast prices to groups of customers and reduce the amount of scalability required.
- There is a technical concern about what level of confirmation is required by the utility regarding whether the demand response event was received. There may be additional message frequency considerations depending on whether:
    - No confirmation is required
    - Confirmation is required from the meter or energy services interface
- Confirmation is required from the customer's equipment. If the customer owns the equipment, the utility cannot guarantee messaging between the interface and the customer equipment. Note that cable and other broadband provider companies have a demarcation point associated with their service delivery. The service reliability is normally only guaranteed to this point.
    - Confirmation is required from a third party, who then has the responsibility to provide it to the customer
- There is a policy issue about the ownership of customer equipment that has technical effects on configuration. There are at least the two possibilities:
    - Customers are permitted to buy their own equipment.
    - Equipment is supplied and supported by the utilities.

Recommendations

- Latency of delivering price information to the customer through in-premises devices should be less than the time in which the price is updated. At the moment, the real-time price is set every five minutes. Not all customers will be on real-time pricing. In any case, the latency required for delivering price information to the customer will likely be set by regulations.
- The utility should identify the expected level of participation of customers in pricing demand response programs.
- The system should be able to permit all customers in the service area to receive pricing information if desired and if specified by policy.
- The utility should be responsible for defining which devices are permitted to communicate with the utility's demand response notification system and what standards are used. This recommendation is intended to be non-discriminatory. It would not prevent a customer from installing devices that are provided by and connected to independent third parties.

- The utility should use a communications standard that permits it to receive and forward confirmation from customer equipment that a demand response event was received by that equipment.
- Customer devices should not require extensive configuration by the customer. The ideal would approach “plug-and-play”.

Technical Requirements

- The pricing information provided to in-premises devices shall be confidential, authenticated and checked for integrity.
- The customer’s usage data when participating in a demand response program shall be authenticated, checked for integrity, and kept confidential.
- Pricing information shall be delivered reliably to in-premises devices because there is a contractual relationship between the customer and utility regarding price.
- The utility shall be able to verify that the demand response event indication was received by the energy services interface (e.g. the meter) or a third-party provider. Ideally this verification should include the time at which the event was received.

Direct Load Control

Description of Application

Demand response can be provided by installing load control devices that receive a signal from the utility or a third party to reduce load. This application does not refer to using the remote disconnect switch to control whole-house load.

Issues

- There are many of the same issues as for Pricing Information to In-Premises devices.
- The utility may need to consider regarding when customers load is re-established after the demand response event. It may be necessary for the system to stagger re-establishment of service so not all the customers start drawing power at the same time. There may be regulatory requirements that drive the technical requirements in this area.

Recommendations

- Direct load control messages should be received by customer equipment within 1 minute of transmission by the utility. There may be a regulation requirement on the expected latency from when the event was sent by the ISO to the utility
- The utility should identify the expected level of participation of customers in direct load control demand response programs
- The system should be able to permit all customers in the service area to receive direct load control information if desired and if specified by policy

- The utility should be responsible for defining which devices are permitted to communicate with their demand response notification system and what standards are used.
- The utility should use a communications standard that permits it to receive and forward confirmation from customer equipment that a demand response event was received by that equipment.
- Customer devices should not require extensive configuration by the customer. The ideal would approach “plug-and-play”

Technical Requirements

- The direct load control message shall be authenticated and checked for integrity.
- The customer’s usage data when participating in a demand response program shall be authenticated, checked for integrity, and kept confidential.
- Direct load control shall be delivered reliably because there is a contractual relationship between the customer and utility regarding participation.
- The utility shall be able to verify that the demand response event indication was received by the energy services interface (e.g. the meter) or a third-party provider. Ideally this verification should include the time at which the event was received.

System Frequency Signal to Customer Load Control Devices

Description of Application

Some customer devices can sense changes in the system frequency that indicate instability and drop load. Frequency sensing can be embedded in devices or be part of an energy management system.

Issues

- Because this function is embedded in the appliance, the utility has little role in the application.
- Most technical requirements in this area may come from the ISO rather than utilities.
- These types of equipment may eventually support the ability to receive demand response signals from the utility. Requirements for that capability are discussed elsewhere.

Recommendations

- None identified

Technical Requirements

- None identified

System Renewable Output to Customers

Description of Application

Customer displays or devices can receive information about the current output of the system's renewable generation. The customer can choose to lower their energy usage or program devices to use less energy when renewable output is low.

Issues

- It is likely that this information could be broadcast to groups of customers

Recommendations

- Customers should be informed of a drop or increase in renewable energy production within approximately 1-5 minutes of its reception by the utility Energy Management System (EMS).
- The system should be able to permit all customers in the service area to receive system renewable energy production level if desired and if specified by policy.
- The utility should identify the expected level of participation of customers in these system renewable output notification programs.

Technical Requirements

- None identified

Distribution Automation Requirements and Recommendations

This section describes the technical issues, requirements, and recommendations for each distribution automation (DA) application.

Automatic Circuit Reconfiguration

Description of Application

A smart distribution system can use communicating switches and circuit reclosers to reconfigure the distribution system during an outage. Automatic reconfiguration allows for a portion of customers who would traditionally be affected by a distribution level outage to have their power restored within minutes.

Issues

- Portions of this application regarding messages between feeder devices require real time latency.
- This application may not be feasible in all parts of a utility's service area.
- There are several possible design approaches:
    - Peer-to-peer among field devices
    - Field devices controlled by substation
    - Field devices controlled by operations
- Distribution automation and Supervisory Control and Data Acquisition (SCADA) have different latency requirements than AMI. Depending on the design approach used, this application may have near-real-time or real-time latency requirements. Requirements for openness in this area may be relaxed because there may not be open technologies that meet the latency requirements.
- There is concern about using AMI networks for low-latency purposes. Many of the existing AMI technologies cannot meet the event rate and volume requirements for AMI and still meet the latency requirements for this application.
- This is an application for which some vendors have designed the peer-to-peer portion with a proprietary protocol but have designed the portion which reports to the control center portion using a standard protocol. The utility may be forced to use a proprietary solution in this case.

Recommendations

- If this application is deployed in certain areas and not in others, utilities should explain why.
- If a separate network or security domain is required for this application, utilities should explain why.
- Portions of this application require real-time latency. The utility should explain how they are going to achieve this latency and what communications network is required to do so. Some possible options are:
    - Sharing a common network that provides priority for this data
    - Choosing separate networks for this data vs. monitoring data or AMI data

- There are at least three approaches to this application, based on where the decision for auto-restoration is made. The utility should explain which approach or approaches they are using:
    - o Peer-to-peer among field devices
    - o Field devices controlled at the substation level
    - o Field devices controlled at an operations level
- The utility should decide how much of the automatic operation is visible to the control center. This path is not as critical as the peer-to-peer path, and requires non-real-time latency (<30 seconds), but could be expensive
- Any data collected within the DA application should be made available to other applications that can benefit from that data, such as voltage levels

Technical Requirements

- The automatic circuit configuration application is critical. The utility shall explain how they will keep auto-restoration commands secure.

Improved Fault Location

Description of Application

Additional sensors with communications can be installed to improve the utility's ability to detect the location of system faults, improving the utility's ability to respond to and correct faults.

Issues

- There are a variety of different technologies available for fault location, with varying levels of accuracy and cost.
- Fault isolation can also be a form of fault location.
- Note that fault location is not "self-healing;" only humans put wires back up.
- This application is the data-gathering portion for the analysis of faults, automatic circuit reconfiguration, and outage management.
- Security for this application is not as critical as for control operations. Spoofing these messages could cause higher costs but are unlikely to cause system failure.
- There is a design decision to be made regarding whether to report the fault as quickly as possible (i.e., real-time latency) or to wait to determine whether the fault is permanent (i.e., greater accuracy, with non-real-time latency).
- Illinois has different definitions about what momentary or permanent outages are compared to standard (e.g., Institute of Electrical and Electronic Engineers - IEEE) definitions.

Recommendations

- The latency can be as long as several minutes from the detection of the fault to when the location is reported to a human being. Any messaging to automatically determine reconfiguration must be resolved before that time with near real time latency (<5 seconds)
- The utility should explain which approach they are using regarding -- reporting more quickly or determining whether the fault location is accurate before reporting -- and why. Issues include:
    - o Number of messages transmitted
    - o Location of data time-stamp
    - o Statistics on when momentary failures are occurring
    - o Determining when faults are being resolved remotely
- There is a potential for thousands of communicating devices for fault location (as many as 10 per feeder on each phase in the case of long feeders). The utility should discuss how scalability is addressed for this application
- The utility should discuss the possibility of using different devices for fault location, and why a particular choice was made
    - o Microprocessor relays, e.g. at the substation
    - o Meters
    - o Dedicated fault location devices
    - o Line reclosers

Technical Requirements

- None identified

Dynamic System Protection for Two-Way Power Flows and Distributed Resources

Description of Application

The existing distribution system is designed and built with the assumption that electricity is supplied to customer end points. As distributed resources become more prevalent, the distribution system will require upgrades that provide sensing of local system conditions and can send control signals and operational settings to devices to maintain safety and stability.

Issues

- Distributed resources and the need for two-way power flows are found in multiple domains: transmission, distribution, and customer premises. If the transmission network is involved, reporting of the status of these applications could go back to the RTO/ISO as well as the utility.
- This application is considered high risk and requires much study before implementing.
- There is an IEEE 1547 standard for how quickly Distributed Energy Resources (DERs) must be off the grid when outages occur.
- How to deal with two-way power flows is an area of uncertainty in the industry at this time.

Recommendations

- The protection operations associated with two-way power flows have real-time latency requirements. They must be completed within 1 second.
- The utility should have a plan for how to enforce standards on a Distributed Energy Resource (DER) connection.
- The requirements for latency of the resource status information (e.g. what level of generation or storage is available) are not well-known at this time. The utility should discuss the assumptions they are making.
- It is important to ensure that there is sufficient metering to detect and predict which direction power is flowing. The utility should explain how their metering scheme will be expanded to permit this application.
- Reprogramming relays (changing settings groups) may cause a loss of use of the device of <1 second. On non-microprocessor-controlled relays, it is not possible to change settings. The utility should explain their plan for reconfiguration and how they will upgrade to microprocessor-controlled relays.
- The utility should consider the possibility that the customer meter may have the capability to enforce safety requirements through the service switch by removing the customer from the grid.
- Note that there are existing Illinois rules and regulations regarding the use of distributed generation with which utilities must comply.

Technical Requirements

- The knowledge of which equipment and which DER is energized/de-energized is a critical safety issue. Latency shall be “non-real-time” or better (<30 seconds) for informing customers of this status. (This assumes that protection has operated correctly.) This requirement may force a particular technology choice because it must be met during outages.

- The utility must have a plan to address the issues of back-feeding and micro-grids in the case of using DER.

Dynamic Volt-VAR Management and Conservation Voltage Optimization

Description of Application

The smart distribution system can monitor voltage and power quality at multiple points throughout the system and communicate control signals to capacitor banks and load tap changers to optimize system voltage and reactive power (Volt-Amps Reactive – VARs) on the system for reliability.

Related to Volt-VAR Management, utilities may be able to maintain a lower regulated voltage which could result in lower energy consumption and increased system efficiency.

Issues

- There could be any combination of the various types of Volt/VAR management:
    - Local control
    - Local control using local meter data
    - Substation control
    - Centralized control
- Some customers might benefit more from voltage management or conservation, depending on the particular characteristics of their load profile.
- Volt/VAR management can help recover line losses.
- Latency requirements are not strict. Volt/VAR control is often done based on long intervals. Currently, it is usually done once per day, with different settings per season. Latency could be non-real-time without loss of benefits. Even a very aggressive system could use an interval of 15 minutes. The control operation may occur only once every several hours.
- The requirement on the remote device for this application is that it must be able to measure voltage. Current and phase angle are needed for more complex algorithms. The accuracy of the voltage measurement is also a factor to consider.

Recommendations

- Capacitor banks should not be switched in and out too frequently.
- The utility should consider the use of meters or feeder devices or a mixture thereof to measure voltage.

- This application may not be required at all customer sites. Rather, a sampling of customers could be used. The utility could choose to sample at higher rates but only report infrequently. The amount of bandwidth required depends on the sample set and whether the data is polled or reported by exception. The utility should provide the rationale for its choice.
- The utility should have a plan for how to expand the capabilities of the system in this application area. Can new areas be added remotely by enabling features on existing devices, or does expansion require deployment of new devices?
- Residential meters configured for voltage recording should be able to record and store voltage at a minimum of 15 minute intervals. (Not all meters need to be configured for voltage recording)

Technical Requirements

- The dynamic Volt/VAR management and conservation voltage optimization applications are a "medium" level of criticality. Spoofing would not cause a great deal of harm unless switching was performed on a very large scale. Control signals shall be secured, but the monitoring data is less critical.

Asset/System Optimization Requirements and Recommendations

This section describes the technical issues, requirements and recommendations arising specifically from each particular asset or system optimization application.

Asset Sizing Optimization

Description of Application

Data provided by AMI meters and new distribution system devices connected by the smart grid network provide the utility with the ability to accurately determine loading and view operational attributes of distribution system components. The increase in system visibility allows the utility to correctly size system components and replace them based on actual operating condition.

Issues

- Note that the "operational attributes" discussed in the description of this application may be things like temperature or voltage drop that indicate how heavily equipment is loaded.
- Both transmission and distribution assets can be monitored.

- Many distribution companies do not have an asset management system.
- There may be a trade-off regarding the mix of devices used to perform the monitoring and how to integrate all the different sources:
    - Transformer meters
    - Customer meters
    - Feeder devices
- This application is not high security since it primarily involves monitoring rather than control.

Recommendations

- This data need not be updated more than about weekly – sufficient to capture monthly or season changes in load.
- It may be useful to run load flow calculations more often than weekly because of the need to support variable generation. Real-time Load Balancing is a similar application requiring much more frequent monitoring.
- There should be a clearly-identified location where this data and the software application will reside. The utility should have a plan for bringing the data together and how to keep it synchronized
- The utility should have a clear plan for archiving this data and how long they will keep the information. They should have an explanation of why they are choosing particular intervals.
- To do this type of sizing is reliant on accurate topology and geographic and electrical connectivity information. In particular, the relationship between customers, phases, meters and transformers is critical. The utility should have a plan for ensuring the accuracy of this data, including updating, distributing, and maintaining topology information before attempting to deploy any asset optimization application. This may require a manual field audit or some electronic means of monitoring.

Technical Requirements

- None identified

Asset Condition Monitoring

Description of Application

Distribution system sensors allow the utility to monitor the real time performance and health of distribution system components. The utility can take corrective action at the appropriate time, increasing system reliability and operational efficiency. This application can likewise apply to the transmission system.

Issues

- There are two components of latency – how quickly is the data measured (e.g., breaker operation time) and how quickly is the data reported.
- Both transmission and distribution assets are monitored.

Recommendations

- There are three different types of data in this application:
  - Alarm conditions should be reported in near-real-time (1-5 seconds)
  - Monitoring data should be reported less often. Reporting frequency depends on the type of equipment and is typically greater than a minute, perhaps as much as a day
  - Control operations should be near-real-time (1-5 seconds)
- There may be a scalability and bandwidth issue from this data because of the number of pieces of equipment being monitored and the frequency of reporting. Reporting by exception where possible is the best practice.
- There is a possible design choice between distributed or central monitoring of equipment. The utility should explain which one is used and why.
- Personnel should be able to query the health and status of the asset monitoring device at any time.

Technical Requirements

- Alarm information from asset condition monitoring must be secure to avoid equipment being taken out of service needlessly.

Enhanced System Modeling and Planning

Description of Application

Data from AMI meters, distribution and transmission system sensors provide the utility an increased ability to validate system models and efficiently plan for system upgrades.

Issues

- None identified

Recommendations

- It is important to know when doing planning where bulk generation, storage, and distributed generation is connected and how much is being provided. Network topology data also needs to be up-to-date. The utility should have a plan for making sure this information is up-to-date.
- Data need be collected no more often than hourly and reported no more often than weekly.
- It is useful to be able to change the measuring and reporting characteristics of meters remotely for this application. It permits the sample size and sample set to be changed with lower cost than current methods.
- Because there are a variety of devices that could be reporting data, standards in the data format are important for this application.

Technical Requirements

- None identified

Distributed Resources Requirements and Recommendations

This section describes the technical issues, requirements and recommendations for each distributed resources application.

Customer Distributed Resource Interconnection

Description of Application

The smart grid can enhance the interconnection of small and large generation and energy storage assets.

Issues

- There are already existing rules in place to be considered for the connection of distributed resources.

Recommendations

- It should be technically possible for the utility to connect a customer's distributed resources at any customer site.

Technical Requirements

- It shall be possible for a meter capable of performing net metering to be installed at any customer site.

Coordinated Management of Distributed Resources

Description of Application

Permitting the utility to communicate with non-utility distributed resources can allow the utility to better manage the distribution system. A utility system that is aware of the operational condition and output of distributed resources can provide better system protection and reliability.

Issues

- Note that this application can potentially be applied to all customers.
- Note that this application may require many of the requirements identified for the application, “Dynamic System Protection for Two-Way Power Flows and DER”.

Recommendations

- The system should be able to separately measure and distinguish between the amount of load and the amount of generation at the customer site
- A utility or aggregator should group customers to a minimum resolution consistent with ISO/RTO policies.
- The message to dispatch load should be received at the energy services interface within 1 minute of transmission by the utility.

Technical Requirements

- None identified

Electric Vehicles: Managed Charging and Dispatch

Description of Application

In the Smart Grid Applications chapter of the Report, two applications associated with electric vehicles were identified. They are discussed together here because their technical requirements are similar. They are:

- **Managed charging.** Increasing penetration of electric vehicles will add a significant load to the electric system which can be managed through the use of smart charging systems.
- **Dispatch.** A potential application of electric vehicles is to allow them to provide stored energy as a backup resource when system and market conditions are appropriate..

Issues

- Note that these applications are still being defined, and that resolving technical issues and requirements may require additional work by industry standards organizations and other stakeholders.
- This is an application that needs to be revisited regularly as standards mature.
- There is a concern that there should be at least state-level standards for regulation and registration of electric vehicles to ensure there is not an incompatible patchwork of local regulations on this issue. The purpose of such standards would be to ensure utilities will always be notified of the use of electric vehicles and can estimate the load on particular feeders.

Recommendations

- The system should permit utilities to send signals to electric vehicle charging systems for reliability purposes, either to prevent charging at inappropriate times, or to request electricity from storage (if that application is implemented).
- The system should permit customers to opt out of the signal to prevent charging, with a notification to the utility so that any authorized fee could be assessed .
- The system should permit utilities to send pricing signals to electric vehicle charging systems to encourage customers to charge vehicles at appropriate times.
- The utility implementing this application should explain how they will determine system constraints to adjust electric vehicle charging in a manner that would prevent excessive load. Constraints could be geographic, seasonal, or time of day.
- The utility implementing this application should explain how their investment will address interactions between generation, storage and electric vehicle use at a customer site. For instance, if local solar generation is capable of charging an electric vehicle, it may not be appropriate for the electric vehicle charger to stop charging based on a signal from the utility
- The utility implementing this application should explain how their investment will address the issue of electric vehicles charging at locations other than their primary billing location

TECHNICAL REQUIREMENTS

- None identified

Transmission Applications Requirements and Recommendations

This section describes the technical issues, requirements and recommendations for each transmission level smart grid application.

Wide Area (Phasor) Measurement

Description of Application

Improved communications and phasor measurement units in various substations monitor phase angle differences at various points 30 times per second which can improve situational awareness and improve grid stability.

Issues

- The primary technical challenge in this application is getting all the data back to a central location.
- Phasor data may be used preemptively, or may be used to analyze data from an event post-mortem.
- The technological maturity of this application is low. The algorithms and user interface for real-time analysis of phasor data are still being developed.
- The ability to measure phasor data is known technology, however, and is widely available in new relay equipment.
- Scalability is not a major issue for this application because relatively few devices are needed.
- To perform grid stability analysis requires high bandwidth data with low latency. The latency determines how often the analysis can be performed.
- This application requires very accurate time synchronization over a wide area.

Recommendations

- The user interface to the operator should be simple enough to clearly identify action that must be taken.
- The utility should explain how they are planning to link phasor analysis and contingency analysis tools for "situational analysis".

Technical Requirements

- If the phasor measurement data is used to operate controls, the data shall be confidential, authenticated, and checked for integrity.

Wide Scale Outage Recovery

Description of Application

Smart grid devices at the transmission and distribution system level allow for improved visibility and control of the electrical system when restoring from a wide scale outage.

Issues

- Note that use of AMI data in outage recovery is dealt with under other applications. This application involves transmission and distribution level recovery.
- The primary difference between the smart grid version of this application and the current situation is the level of detail available, and the algorithms used to coordinate outage management with previous load information.
- This application involves use of phasor data as well as normal monitoring data.
- There are manageability concerns due to crossing transmission system boundaries.

Recommendations

- Latency and bandwidth requirements are not high after the event (>5 seconds).
- The utility should explain how they will use phasor and load information from before the event to determine the order of recovery.
- Scalability is not a significant requirement. This application does not require many data points but they must be reliable.
- Recommend participation from the ISOs.

Technical Requirements

- The utility communication system for transmission and distribution devices shall be maintained during a wide-scale outage in order to permit wide-scale outage recovery to be performed.

Enhanced Physical Security

Description of Application

Enhanced physical security of substations and their assets improves system reliability.

Issues

- The primary smart grid information traffic for this application is video monitoring and alarm reports from various sensors.
- This application is primarily a transmission application.
- This application is typically only performed over wide area network.
- Video monitoring may require high bandwidth. Compression and reporting algorithms may reduce this requirement.

Recommendations

- Alarms should have near real time latency (<5 seconds).
- The utility should consider that there may be control operations needed, e.g., zooming cameras.

Technical Requirements

- Enhanced physical security services shall be protected from eavesdropping, spoofing, and denial of service.

Summary Tables

This section summarizes in a set of tables the significance of each smart grid design issue with respect to each of the applications considered.

LEGEND

The smart grid applications in each category are presented in the rows of each table and the smart grid design issues are presented in columns. The icons in each table cell identify the level of technical requirements and importance the particular design issue has with respect to the particular design issue, as follows:

○ This application has a low level of requirements with respect to this design issue. Utilities may not need to address this category in their planning.

◘ This application has a medium level of requirements with respect to this design issue. Utilities should address this category in their planning.

● This application has a high level of requirements with respect to this design issue. Utilities should address this category in detail in their planning. Note: for the Technical Maturity and Risk category, this icon means maturity is a concern, not that it is mature.

(empty) This category of requirements was not discussed with respect to this application. It may not be significantly applicable to this application.

AMI APPLICATIONS

Application	Capacity			Tech Maturity & Risk	Open Standards	Security	Manageability	Upgradeability	Scalability	Reliability	Interactivity
	Latency	Data Volume	Event Rate								
Core AMI – Remote Meter Reading	◎	◎	●	○	◎	●	●	●	●	◎	
Remote Connect/Disconnect	◎	○	○	◎	◎	●	●	●	●	◎	○
Outage Management Support	◎	○	●	●	◎	◎	●	●	●	●	
Power Quality / Voltage Monitoring	○	●	◎	●	◎	◎	●	●	○	○	
Customer Prepayment using AMI	◎	○	○	●	◎	●	●	●	○	●	●

CUSTOMER-ORIENTED APPLICATIONS

Application	Capacity			Tech Maturity & Risk	Open Standards	Security	Manageability	Upgradeability	Scalability	Reliability	Interactivity
	Latency	Data Volume	Event Rate								
In-Premises Devices / Usage Data	◎	◎	◎	◎	●	●	●	●	●	◎	●
Customer Web Portal Energy / Cost	○	○	○	◎	●	●	●	○	●	○	●
Outage Notification to Customer	○	○	◎	◎	◎	○	◎	◎	●	◎	●
Third-Party Use of Customer Data	○	●	○	●	●	●	●	○	◎	◎	●

DEMAND RESPONSE APPLICATIONS

Application	Capacity	turi ty	Sta nd	cur ity Se	ge ahi	na ahi	gra de	ala bili	iab ilit	cti vit	era

	Latency	Data Volume	Event Rate								
Pricing Data to In-Premises Devices	○	○	⭘	●	●	●	●	⭘	⭘	●	●
Direct Load Control	⭘	○	⭘	⭘	●	●	●	⭘	⭘	●	●
Frequency Signal to Cust. Devices	●	○	○	●	○	○	○	⭘	●	○	⭘
Renewable Output to Customers	⭘	○	⭘	●	●	●	⭘	○	⭘	⭘	●

DISTRIBUTION AUTOMATION APPLICATIONS

Application	Capacity			Tech Maturity & Risk	Open Standards	Security	Manageability	Upgradeability	Scalability	Reliability	Interactivity
	Latency	Data Volume	Event Rate								
Automatic Circuit Reconfiguration	●	○	○	◎	●	●	●	●	◎	●	
Improved Fault Location	◎	○	◎	◎	◎	◎	●	●	●	○	
Dynamic System Protection / DER	●	◎	○	●	●	●	●	●	◎	●	◎
Dynamic Volt/VAR Management	○	○	◎	◎	◎	◎	●	●	◎	◎	
Conservation Voltage Optimization	○	○	◎	◎	◎	◎	◎	●	◎	◎	

ASSET/SYSTEM OPTIMIZATION APPLICATIONS

Application	Capacity			Tech Maturity & Risk	Open Standards	Security	Manageability	Upgradeability	Scalability	Reliability	Interactivity
	Latency	Data Volume	Event Rate								
Asset Sizing Optimization	○	●	○	○	◎	○	●	●	●	○	
Asset Condition Monitoring	◎	●	◎	◎	●	●	●	◎	●	◎	
Enhanced System Model/Planning	○	○	○	◎	●	◎	●	●	○	○	

DISTRIBUTED RESOURCES APPLICATIONS

Application	Capacity			Tech Maturity & Risk	Open Standards	Security	Manageability	Upgradeability	Scalability	Reliability	Interactivity
	Latency	Volume	Event Rate								
Customer DER Interconnection	◉	◉	○	●	●	●	●	◉	●	●	◉
Coordinated Management of DER	●	◉	○	●	●	●	●	◉	◉	●	◉
Electric Vehicles: Charge / Dispatch	◉	○	◉	●	●	●	●	●	●	●	●

TRANSMISSION APPLICATIONS

Application	Capacity			Tech Maturity & Risk	Open Standards	Security	Manageability	Upgradeability	Scalability	Reliability	Interactivity
	Latency	Data Volume	Event Rate								
Wide Area (Phasor) Measurement	●	●	●	●	●	●	●	◉	○	●	◉
Wide Scale Outage Recovery	◉	○	◉	◉	●	●	●	●	○	●	
Enhanced Physical Security	◉	●	○	○	○	●	◉	●	◉	●	

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Cost-Benefit Framework

Introduction

Cost-Benefit Framework Scope and Objectives

In the Commission's Order, the Collaborative was tasked with developing cost-benefit concepts to be applied to smart grid investments. Language in the Order asks for recommendations on the definition of "methods of estimating, calculating and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs)." Based on its understanding of the Order, the Collaborative agreed on the following objective: to develop a standardized cost-benefit framework for smart grid investments so that future debates about the cost-effectiveness of potential smart grid investments in Illinois can center on the reasonableness and supportability of estimated costs and benefits rather than the methodology for conducting cost-benefit analysis. Therefore, the emphasis of the Collaborative has been the development of a methodology and guidance for conducting an analysis rather than actual evaluation of potential smart grid investments.

The cost-benefit analyses identified herein are intended to aid the Commission in considering the appropriate smart grid solution through the application of the methodologies described in this chapter. In particular, the cost-benefit analyses require a meaningful assessment of the risks implicit in the investment. Such considerations should include identifying viable alternative investments and approaches to the design endorsed by the utility. These analyses and methodologies are intended to recognize the need of the Commission, consumers, and other stakeholders for assurance that a cost-effective solution is being proposed.

The Collaborative tried to answer the following questions:

- How should the Commission analyze and evaluate the cost-benefit of smart grid investments?
- What costs and benefits should be included in the analysis – and how should costs and benefits be captured?
- How should the analysis be structured?

Traditional Cost-Benefit Principles and Guidelines

Cost-benefit analysis is usually concerned with estimating and summing the equivalent value of the benefits and costs of investments to establish whether they are prudent and worthwhile on an economic basis from a single point of view or perspective. The process generally involves determining the cost of the investment (including both the initial investment and ongoing expenses) and comparing this cost to the expected benefits from the investment. Typically, the following steps are used to reach a conclusion:

- All factors or variables potentially having an impact (positively or negatively) on the investment are identified. An estimate or assumption is made as to the amount of impact each variable is expected to have on the project – sometimes called the "quantification" of variables.

- All aspects of the investment must be expressed in common terms – the most usual being monetary. The process of taking the quantitative impact of each factor or variable and converting into equivalent monetary value is sometimes called "monetization." This conversion into equivalent monetary terms involves accounting for the time value of money – usually by converting the future expected streams of costs and benefits into a present value amount via a discount rate. In financial calculations, the discount rate is sometimes equal to the entity's weighted average cost of capital (WACC), representative of the market rate of return for the mix of financial assets the entity uses to finance capital investment (capital structure).

- Calculations of multiple valuation measures can be performed to emphasize different aspects of the financial profile of the investment. Some of the most common are:
  - Payback Period – the period of time required for the return of and on an investment to "repay" the cost of the original investment.
  - Breakeven Point – the point at which cost or expenses and revenue are equal and there is no net gain or loss. This is often expressed in terms of units sold in a production environment in which there are fixed and variable costs.
  - Net Present Value (NPV) – the difference between the present value of cash inflows and the present value of cash outflows over a defined period, at a given interest rate. In calculations for most corporate decision-making, the cost of capital expected to support the investment is used as the interest (or discount) rate.
  - Internal Rate of Return (IRR) – the discount rate that makes the net present value of all cash flows from a particular investment equal to zero. In contrast with NPV, which is an indicator of the magnitude of the investment return, IRR is an indicator of the efficiency or yield of an investment.
  - Benefit-Cost Ratio – the ratio of the present value benefits of an investment to its present value costs.

- Since capital is often constrained (i.e., entities have insufficient resources to invest in every attractive project), investments are often compared in a capital budgeting process before final investment decisions are made. Quantitative as well as qualitative factors (e.g., fit with strategy, public policy issues) typically factor into the capital budgeting decision.

Cost-Benefit within the Context of Smart Grid

Certain challenges arise when attempting to apply traditional cost-benefit analysis to a proposed smart grid investment. Some of the key ways in which evaluation of the costs and benefits of smart grid investments can be different from traditional investment analyses include:

- All costs and benefits related to smart grid may not be borne or realized by the investing entity. This raises questions such as: should these additional costs and benefits be incorporated into the analysis? If so, then how (in practice) this multi-entity perspective be modeled in the analysis?

- Uncertainty with respect to the magnitude of benefits is not unique to smart grid. However, there are some potential benefits associated with smart grid (e.g., reliability value, environmental impact) that present particularly difficult issues in calculating the level of benefit.

Over the past few years, there have been various models and constructs put forth related to evaluating smart grid investments. A review of several of the most prominent revealed that there was no single reference that adequately addresses all of the concerns identified within the scope of the ISSGC cost-benefit framework. However, the following references as well as other relevant state regulatory decisions that have addressed these and other similar issues can provide considerable insight into smart grid cost-benefit analysis and are worthy of note.

- EPRI published a report in January 2010 on an approach for evaluating the DOE's Smart Grid Demonstration Projects.[38] It leverages many studies that have been performed previously and represents the most comprehensive approach to smart grid cost-benefit analysis put forth to date. The ten-step approach outlined in the report can be applied generically to most smart grid investments, but the discussion within each of the steps focuses on issues specific to smart grid. The ten steps are organized into three groups as follows:

    1. Characterize the Project: review project elements; identify smart grid functions associated with the project; assess the characteristics that are reflected in the project;

    2. Estimate Benefits: map each function onto a standard set of benefits; define the project baseline and how it will be estimated; identify and obtain the data necessary; quantify the estimated benefits; convert the benefit estimates to monetize the values;

[38] *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*. EPRI, Palo Alto, CA: 2010. 1020342.

3. Compare Costs to Benefits: estimate the relevant costs; compare costs to benefits and summarize the cost-benefit.

- Several other studies and reports address specific aspects of smart grid analysis. Each of the following is particularly useful within its respective scope:

  - McKinsey & Company developed a spreadsheet model for comparing the costs and benefits of AMI and made it available to energy providers, regulatory commissions, customer advocacy groups, and AMI vendors in August 2006 to assist in analyzing AMI deployments.[39] The model captures user inputs regarding the expected capital costs and utility O&M savings and calculates the resulting cash flows, NPV, and IRR. While useful in tracking costs and benefits for operational impacts in the AMI context, it is not directly applicable to many smart grid applications, since it does not incorporate costs or benefits associated with demand response, reliability, or societal benefits.

  - California Energy Commission sponsored study on the value of distribution automation.[40]

  - EPRI published a report on societal benefits of smart metering.[41]

  - Lawrence Berkeley National Laboratory published a report for the DOE's Office of Electricity Delivery and Energy Reliability on the value of service reliability.[42]

  - Brattle Group published a report for PJM and the Mid-Atlantic Distributed Resources Initiative (MADRI) on quantifying demand response benefits in PJM.[43]

- The following four sections describe the Collaborative's recommended Cost-Benefit Framework for smart grid investments and provide related recommendations on the use of the Cost-Benefit Framework

  - Elements of the Framework and General Requirements

  - Cost-Benefit Analysis Mechanics and Assumptions

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[39] *Advanced Metering Infrastructure Example Project Valuation Model – Version 1.00*; McKinsey & Company; August 7, 2006

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[41] *Characterizing and Quantifying the Societal Benefits Attributable to Smart Metering Investments.* EPRI, Palo Alto, CA: 2008. 1017006.

[42] Sullivan, Michael; Mercurio, Matthew; Schellenberg, Josh; Freeman, Sullivan & Co. "*Estimated Value of Service Reliability for Electric Utility Customers in the United States*," prepared for the U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, LBNL-2132E June 2009.

[43] Brattle Group. *Quantifying Demand Response Benefits in PJM,* prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

- Quantification and Monetization of Costs and Benefits
- Monitoring and Verification of Results

Elements of the Framework and General Requirements

This section describes the overall structure of the recommended cost-benefit framework for the economic evaluation of smart grid investments, including an identification of the basic "building blocks" of the framework. The section also provides some general recommendations to the Commission on how the framework should be used.

Use of the Cost-Benefit Framework

The cost-benefit framework described in this section is intended to apply to smart grid investments only. The framework is not intended to exclude investment in pilot projects whose purposes include substantiation of cost-benefit estimates. The framework is also intended to include comparative cost-benefit assessments of alternative approaches to smart grid investments, including examinations of different approaches of achieving the estimated benefits of the proposed investment. Although smart grid investments may differ in the specific kinds of estimated costs and benefits they include, the Collaborative has attempted to define a construct that is sufficiently robust and flexible to support the evaluation of all smart grid applications. The cost-benefit framework can provide the structure for an economic evaluation of a proposed smart grid investment or of smart grid investments already made. Finally, the Collaborative has not provided recommendations on the controversial issue of cost allocation. Allocations for the purpose of recovering costs may or may not be subject to a different methodology from that used for projecting costs and benefits.

Building Blocks

The major elements or "building blocks" of any cost-benefit analysis, including this cost-benefit framework, are the estimated costs and benefits associated with the investment and the discount rate used to calculate the present value of future cost and benefit streams. The following sections provide a generic description of the elements of the cost-benefit framework; however, it should be noted that the specific costs and benefits used to evaluate an investment will vary by investment and by the perspective of the analysis.

Estimated Costs

Consistent with standard accounting practices, costs generally can be expected to fall into the following categories:

- Capital (changes in capital spending)
  - Hardware
  - Software
  - Labor
    - – Installation
    - – Software integration
- O&M (changes in on-going direct/indirect support costs associated with ongoing maintenance and operation of capital investments)
  - Labor
  - Software
  - Hardware
  - Service agreements
  - Consumer education
  - Program administration
- Stranded costs that may be created by the investment
- Potential negative impacts
  - Customer, including negative impacts on customer privacy, customer safety, customer equipment, or customer costs
  - Technology, including risks and costs resulting from increased reliance and dependence on digital technologies
  - Employee and Public Safety

Utility Operations, including potential increases in undetected energy theft, legal costs, or customer care costs.

Potential Benefits

Potential sources of benefit may be categorized according to the entity that would initially and directly realize the benefit. These categories include:

- Customer Value – potential benefits realized by individual electricity consumers in Illinois, including reductions in customer costs for electric delivery service and energy supply service, and decreases in outages and improved power quality

- Utility Value – potential benefits realized by state jurisdictional distribution or transmission providers, including reductions in operating costs, reductions and/or deferrals in capital spending, increases in system reliability, and improved employee safety.

- Regional Electricity Market Value – potential benefits observable in regional wholesale electricity markets. This could include reductions in price volatility, reductions in the prices of energy supply and capacity resulting from changes in the magnitude or timing of electricity demand and deferrals or reductions in transmission and generation investment.
- RTO/ISO Value – potential benefits to the regional transmission operator or independent system operator. This could include increased regional system reliability grid stability, improved situational awareness, improved forecasting, and improvements to the settlement process
- Competitive Supplier/Third Party Value – potential benefits to alternative retail electric suppliers, non-state jurisdictional entities, and other third parties
- Societal Value – potential benefits realized by society as a whole, not necessarily Illinois electricity consumers (e.g., environmental benefits, improvements to public health/safety, economic development, and improvements to or the expansion of broadband communications networks).

Discount Rate

Smart grid applications, like other investments, can be expected to require upfront capital investments and additional on-going support for future capital and operations and maintenance (O&M) spending. The realization of benefits may occur gradually and over extended periods of time. (Specific considerations for the appropriate time horizon for the analysis are described elsewhere in this chapter.) Therefore, all cost-benefit analyses in support of a smart grid investment should reflect and adjust for the expected timing of estimated costs and benefits. Future expected streams of costs and benefits should be converted into a present value amount via an appropriate discount rate. Guidance on appropriate discount rates for smart grid cost-benefit analysis is provided in the Multiple Views/Perspectives section of this chapter. However, the discount rates used in the analyses are not intended to affect the rate of return that the Commission may set for future cost recovery on the investment.

General Requirements

The cost-benefit analysis of smart grid investments is intended to be comprehensive. However, in order for all of the elements to be incorporated into an economic analysis, all quantified costs and benefits must be expressed monetarily. The analysis should include any factor (i.e., cost or benefit) that meets the following criteria:

- Significant -- can be expected to have a meaningful economic impact on the utility's investment decision or are relevant to the Commission's approval decisions

- Quantifiable and transparent -- can be reasonably and transparently quantified and monetized
- Relevant -- is relevant to the analysis, specifically including the costs of achieving claimed benefits.

Costs and benefits should only be counted once; there can be no double-counting of benefits.

All costs and benefits used in the analysis should be incremental to the investment when compared with a baseline or "business as usual" scenario. The baseline scenario should reflect the related costs or benefits that would be anticipated if the investment were not made.

Uncertainties

Some factors in a cost-benefit analysis may have a high degree of variability and/or uncertainty. Key assumptions underlying the analysis, including those that drive estimates of major cost components, should be clearly documented and the variability or uncertainty of estimates should be incorporated into those estimates. The cost-benefit analysis should discuss the uncertainties associated with estimates of costs and benefits over the term of the payback period.

Treatment of Stranded Costs

This refers to the treatment of existing assets retired before they have reached the end of their useful life and have been fully depreciated (the stranded costs). The Collaborative discussed whether stranded costs should be included or excluded from the cost-benefit analysis. In a strictly economic sense, these stranded assets represent sunk costs since the investment is in the past and the investment in a new technology should be evaluated on its own merits. However, from a cost recovery standpoint these investments are being recovered in rate base and are not fully "paid for" – although they have been "paid for" in a procurement/economic sense. The magnitude of resulting stranded investments may bear on the prudence of the investment decision for regulatory purposes. The cost-benefit analysis should recognize as a separate line item any stranded costs that would result from the smart grid investment.

Implementation Timing

Smart grid technologies and implementation methods can reasonably be expected to improve in efficacy and scope over time, while costs of the equipment and technologies may reasonably be expected to change over time. Thus, the relative costs and benefits of smart grid investments and approaches will depend on the timing of implementation. To the extent that they are known or can reasonably be anticipated, a cost-benefit assessment of smart grid investments and approaches should include discussion of the potential change in benefits and costs that may occur over time assuming various implementation schedules.

Potential Overlap with Statutorily-Required Energy Efficiency and Demand Response Programs

Costs and benefits resulting from statutorily-required energy efficiency and demand response measures and programs should be identified and accounted for separately from costs and benefits associated with smart grid investments. Any amounts charged (or benefits flowing) to customers for statutorily-required measures and programs should be separated from any amounts charged (or benefits flowing) to customers for smart grid investments when calculated and itemized.

Alternative Approaches

A cost-benefit assessment of smart grid investments and approaches should include identification and discussion of other investments or approaches (if any) that reasonably might achieve similar or better results. To the extent those expected benefits can be achieved through other investments or approaches, assessment of the incremental costs and incremental benefits of smart grid investments or approaches should be done relative to the cost and benefit of such investments or approaches, so as to identify and isolate the "extra" costs and benefits attributable to smart grid, if any.

Cost-Benefit Analysis Mechanics & Assumptions

This section contains identification and discussion of issues related to the analysis itself and the specific assumptions and inputs required in performing the analysis. The following issues were discussed in the Collaborative and are included in this section:

- Multiple Views/Perspectives
- Sensitivity Analysis
- Benefits Dependent on Penetration Levels and/or Changes in Customer Behavior
- Appropriate Timeframe for Cost-Benefit Analyses
- Treatment of Smart Grid Applications with Shared Infrastructure Investments

Introduction

One of the challenges associated with performing cost-benefit analysis of smart grid investments is that the investment required may involve parties in addition to the utility. For example, some programs requiring an "in-premises device" contemplate having the customer or third party make this initial investment. Similarly, the benefits realized by a smart grid investment may extend well beyond the boundaries of the investing utility and its customers to third parties or society as a whole. Finally, the benefits realized by a "participant" in a smart grid application/program may be different from those of a "non-participant." From a cost-benefit perspective, this is different from most traditional analyses in which the potential investor incurs the full cost and the investment decision is based on the cash flows that are expected to revert directly back to the investor. This lack of congruity between the investor and the beneficiary adds a level of complexity to smart grid cost-benefit analysis.

The cost-benefit evaluation of demand-side management programs shares many of the same challenges as the evaluation of smart grid programs – a complexity that has been addressed in that arena by analyzing the investment from a series of vantage points or perspectives. The Collaborative turned to the legacy of demand-side management (DSM) program evaluation as a starting place in the development of a smart grid cost-benefit framework.

Multiple Views/Perspectives

There is a considerable body of work that exists for evaluating DSM and energy efficiency programs according to different perspectives. Perhaps the definitive source in this area is the *California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects* most recently produced by the California Energy Commission in October 2001 (with predecessor documents going back to 1983). While portions of this work may not be directly applicable to some smart grid investments, many of these concepts are being applied to smart grid by forerunners and experts in the field. In fact, EPRI's *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects* (January, 2010) recommends directly applying the tests and calculations from the California Standard Practice Manual to evaluation of the projects receiving funds from DOE's Smart Grid Investment Grant program. At least some of its rationale for this is that "in general, these tests are applicable to smart grid evaluations, because a major driver of smart grid benefits will be avoided supply side costs realized through demand reductions, and assessing these impacts was the original driver behind the development of these models."[44]

Within the context of DSM and energy efficiency, many state jurisdictions require multiple perspectives to be presented (i.e., multiple tests performed), regardless of the test (or tests) that are ultimately relied upon for decision-making. The different combinations of costs and benefits could conceivably result in certain smart grid applications "passing" according to some views/perspectives, but not others – which leads to questions surrounding which views/perspectives to weigh more heavily. There was a specific concern addressed by some Collaborative participants that smart grid investments that were deemed uneconomic according to other views/perspectives would be implemented based solely on a view/perspective that included societal benefits.

The following "tests" represent those utilized historically for DSM programs that are now beginning to be applied to smart grid investments:

- Participant Cost Test (PCT). This test measures the quantifiable costs and benefits of the program to the participating consumer, attempting to determine if the participant is better off. Within the context of smart grid, it might be appropriate for this test to be performed when evaluating customer-oriented applications (those offering products and/or services on the customer (load) side of the meter).
- Ratepayer Impact Measure (RIM) – This test measures the net impact of the program on customer rates/bills to determine if overall rates will be lowered. The RIM test incorporates the utility's lost revenues as a key cost component (i.e., reduced consumption impacting the utility's recovery of its fixed costs).
- Program Administrator Cost (Utility Cost Test). This test measures net program costs, like a TRC test, but excludes participant costs. Its concern is determining if revenue requirements are reduced. This test does not include the utility's lost revenues as a cost (which is the primary difference between this test and the RIM test).
- Total Resource Cost (TRC). This test measures the net cost of the program as a resource option, including both the utility's and participants' net costs, in an attempt to determine if resource efficiency is improved.
- Societal Cost Test. This test expands the TRC to incorporate external benefits (e.g., environmental, third parties, societal). Competitive Supplier/Third Party Value benefits (benefits to alternative retail electric suppliers, non-state jurisdictional entities, and other third parties) may be appropriate for inclusion in the Societal Cost

[44] *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*; EPRI, Palo Alto, CA: 2010. 1020342; p.4-24

Test. Societal Value benefits should only be included as an element in the Societal Cost Test.

The following matrix identifies the various potential costs and benefits associated with the respective tests in which they would be included.

Test	Included in Test Calculation	
	Potential Costs	**Potential Benefits**
Participant Cost	• Costs incurred by those customers participating (initial capital cost including sales tax, ongoing O&M costs, removal costs less salvage value) • Potential negative impacts on those customers participating	• Reduction in utility bills for those customers participating • Tax credits paid to those customers participating • Utility incentives paid to those customers participating
Ratepayer Impact Measure (RIM)	• Initial and ongoing costs incurred by the utility (e.g., hardware, software, customer education, administration, customer incentives costs) including stranded assets • Utility's lost revenue from reduction in sales • Potential negative impacts on the utility	• Utility avoided costs (capital or O&M) • Utility's revenue gains from increase in sales
Program Administrator Cost	*Same as RIM, but excluding the utility's lost revenues* • Initial and ongoing costs incurred by the utility (e.g., hardware, software, customer education, administration, customer incentives costs) including stranded assets • Potential negative impacts on the utility	*Same as RIM, but excluding the utility's revenue gains* • Utility avoided costs (capital or O&M)
Total Resource Cost (TRC)	*All of those included in the Participant and RIM, but excluding the utility's lost revenues and customer incentives paid by the utility* • Costs incurred by those customers participating (initial capital cost including sales tax, ongoing O&M costs, removal costs less salvage value) • Initial and ongoing costs incurred by the utility (e.g., hardware, software, customer education, administration costs) including stranded assets • Potential negative impacts on those customers participating • Potential negative impacts on the utility	*All of those included in the Participant and RIM, but excluding the revenue impacts from sales (to/from participant and customer) and customer incentives paid by the utility* • Utility avoided costs (capital or O&M) • Tax credits paid to those customers participating

Societal Cost	*All of those included in the TRC, plus the following externalities:* • Costs incurred by third parties associated with external benefits included • Potential negative impacts on third parties associated with external benefits included	*All of those included in the TRC, plus the following externalities:* • Benefits accruing to society as a whole (e.g., environmental, public safety, economic productivity) • Benefits accruing to third parties, but not to customers or the utility

Recommendations

The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analysis to be filed with the regulatory commission. The ICC and others should have the benefit of these different perspectives when weighing the merits of smart grid investments.

All known and measurable costs required for the implementation of a particular application (whether borne by the customer, utility, or third party) should be incorporated into the cost-benefit analysis in the appropriate view(s).

- A Total Resource Cost perspective for investments should be presented by the utilities – both with societal costs and benefits and without societal costs and benefits
- Other perspectives that should be presented include a Ratepayer Impact view (depicting how rates would be impacted) and a Customer/Participant view (depicting the impacts of customer-specific costs and benefits).

The Customer/Participant Test is relevant for smart grid applications that meet both of the following criteria:

- Customers may to choose to participate in the application (or not)
- Participants would be expected to realize quantifiable benefits not realized by non-participants.

The Societal Cost Test is the only test that would include societal costs and benefits.

As appropriate to each test, the cost-benefit analysis should separately identify:

1) those costs and benefits that will be directly incurred or realized by ratepayers through the traditional ratemaking structure

2) those costs that can be expected to be incurred by non-utility parties

3) those benefits that will flow, if at all, through the wholesale price of energy or other markets

4) those benefits associated with broader societal objectives or results that are not necessarily reflected in regulated customer rates.

For certain tests, the rate of return on utility investments could be a reasonable choice for a discount rate. However, the use of a different discount rate may be appropriate for other tests because customers may have a different assumed cost of capital. (The discount rates used in the analyses are not intended to affect the rate of return that the Commission may set for future cost recovery on the investment.) Discount rates used in the analyses, and the rationale for their use, should be clearly documented.

The Commission's decision to approve (or not approve) any particular smart grid investment may be based on a number of considerations, some of which could be outside the context of the cost-benefit analysis (e.g., policy considerations). However, the Collaborative believes that application of the cost-benefit framework defined herein will provide the Commission with valuable perspectives on the economic value of the smart grid investment -- perspectives that should be given considerable weight by the Commission in its overall evaluation.

The Collaborative does not believe that cost-benefit analysis or any particular cost-benefit test or tests should be considered dispositive. However, as indicators of the economic value of the investment to the utility, ratepayers, participants, and society, the Collaborative believes that the results of the cost-benefit analyses should be of central importance in informing the Commission's ultimate decision. For this reason, the Collaborative believes that the Commission should not approve an investment that does not pass at least one of the tests.

Furthermore, some stakeholders believe that the Commission should reject any smart grid investment which passes only the Societal Cost Test. Other stakeholders believe that the Commission should approve the investment if the evaluation of one or more of the tests is sufficiently strong to ensure that, on balance, the investment would likely serve the best interest of Illinois ratepayers.

Sensitivity Analysis

Most cost-benefit evaluations include some form of sensitivity analysis in which key variables, especially those that are less certain, are modified to determine how much results would change from the "base case" (i.e., that with the greatest level of expectation). There is consensus among the Collaborative that sensitivity analysis should be performed for smart grid investments.

Recommendations

The utility should be required to include a sensitivity analysis as part of the cost-benefit information filing to support their smart grid investments. While reasonable discretion should be provided in terms of the variables and assumptions to be included, the sensitivity analysis should:

- Identify the key variables from the cost-benefit analysis that merit sensitivity analysis. Good candidates for inclusion are variables (such as emission costs and reliability) that have a wide range of potential values and/or are more subjective in nature.
- Produce cost-benefit results using alternate values for the variables in order to demonstrate the sensitivity/impact various scenarios might have on the economic profile of the smart grid investments.

Benefits Dependent on Penetration Levels and/or Changes in Customer Behavior

For some smart grid applications (e.g., those associated with demand response), the level of benefits expected is dependent on an assumed level of customer participation and/or changes in customer behavior. Therefore, there is a degree of uncertainty with respect to benefits that should be expected from these smart grid applications.

Recommendations

The utilities should make best efforts to incorporate into the cost-benefit analysis reasonable estimates for customer participation, the impacts on customer bills, usage, and peak load reduction, as well as estimates of the persistence of customer behavior and estimated benefits over a lengthy period of time. Costs needed to realize the projected behavioral impacts should be included in the cost-benefit analysis.

The degree of participation, assumed behavioral impacts, and persistence of customer behavior changes should be among the variables included in sensitivity analyses.

Appropriate Timeframe for Cost-Benefit Analysis

Evaluation issues arise if the useful life assumed for economic evaluation purposes is significantly different from the actual life of the asset (i.e., an overly optimistic or pessimistic projection of benefits could result). Also, it may be appropriate to bundle a set of applications together for evaluation purposes if the applications are dependent upon each other to deliver the intended functionality. For example, an investment in Core AMI functionality may also include outage management and remote connect/disconnect functionality. In cases such as this, questions may arise as to how to evaluate the package appropriately from a useful life perspective.

Recommendations

An entire "package" of related smart grid investments/applications should be included in a consolidated cost-benefit evaluation and considered over a single timeframe. However, smart grid investments/applications should be grouped into a package only if they are needed to function together or provide otherwise unachievable synergies. To the extent that it is feasible to separate underlying platforms from individual applications, smart grid applications contained within a package should still be subject to an individual cost-benefit analysis based on their stand-alone incremental costs and benefits.

The length of time over which a cost benefit analysis is calculated should reflect the projected useful life of the smart grid investment or system. "Useful life" means the continuous period of time when the components and systems of the investment operate correctly and reliably to perform their designed functions. Absent any persuasive contrary evidence, the depreciable life of the investment for regulatory (non-tax) purposes should match the useful life of the investment. The utility should document the basis for its determination of the useful life of the investment. The utility should also document the length of time over which reasonable customer benefits can reliably be estimated.

Since payback period is an important consideration in technology investments with potentially short useful lives, a payback period should be calculated based on the present value of the annual cash flows of the smart grid investment or package.

Treatment of Smart Grid Applications with Shared Infrastructure Investments

Some issues in this area were dealt with in the context of the appropriate timeframe issues discussed earlier in this document. One of the remaining questions was: should applications that are included in a package as part of a shared infrastructure investment (an investment in infrastructure that would support multiple applications) be considered individually? Of concern are the multiple permutations that could occur with a shared infrastructure investment that enables/facilitates multiple smart grid applications by the utility or others. It could become unduly burdensome were a separate analysis required for each individual application and each potential combination.

Another key issue is how to deal with an infrastructure investment that could potentially provide revenues from unregulated activities by the utility or others (for example, communications infrastructure). Of importance in a cost-benefit evaluation is ensuring that expectations for non-regulated revenue are accounted for appropriately, and that regulated utility investment (expected to be funded by "above-the-line" utility revenues) is justified by the regulated utility benefits.

Recommendations

Wherever and to the extent possible, a utility's shared infrastructure investments (those that support multiple applications) should also incorporate the known and measurable costs and benefits of all of the associated applications in the cost-benefit analysis. When that is not possible, the infrastructure investment should be supported in the cost-benefit analysis by only those applications being used to justify the utility investment. (Potential future applications and benefits not included as part of the implementation package could be treated separately as an option value.) The rationale behind the packaging of investments should be clearly identified in the utility's proposal.

The cost-benefit analysis should not attempt to assign or allocate the relative amount of the total investment and benefits to the individual applications that are supported in the implementation of the shared infrastructure. However, in order to demonstrate the net benefit of each application supporting the infrastructure investment, each application should be subjected to an individual cost-benefit analysis based on the incremental costs and benefits of the application (excluding cost of the shared infrastructure).

Allocations for the purpose of recovering costs in a rate proceeding may be subject to a different methodology from that used for projections in a cost-benefit analysis.

Potential non-regulated, third party, or incidental revenue from smart grid infrastructure investments should be reflected in the cost-benefit analysis.

Quantification and Monetization of Costs and Benefits

This section identifies and contains Collaborative discussion and recommendations surrounding smart grid-related costs and benefits that are difficult to quantify and/or monetize. The following issues are included in this section:

- Monetization of Environmental Benefits
- Monetization of Reliability Benefits
- Treatment of Smart Grid Applications with Shared Infrastructure Investments
- Monetization of Benefits Associated with Retail Generation Supply Prices

Monetization of Environmental Benefits

If it is determined that environmental benefits should be included in a cost-benefit analysis, the projected benefits must be quantified. In some cases, environmental benefits can be estimated based on the average cost of installing remediation equipment, such as emission reduction technology. For example, the estimated cost of building a flue gas desulfurization scrubber and the corresponding reduction in SO_2 expected can be estimated with a high degree of certainty. In other cases, there are market instruments from which the benefits can be readily calculated (e.g., spot and future values of allowances that trade hands in market exchanges). Often, if entities have a choice of environmental compliance alternatives (e.g., in the case of SO_2 there are allowances that can be purchased or a generator can switch fuels or install a scrubber), they will choose the long run least-cost alternative. Since spending capital to install technology is an alternative, this cost often represents a ceiling for price projections of associated market instruments or allowances.

Currently, valuing CO_2 reduction is problematic with respect to the methodologies above. The market for instruments cannot fully develop unless and until carbon constraint legislation is passed (acceptable emission levels and rules for compliance are not in place yet), nor are there commercially available technological solutions from which carbon reduction costs can be determined.

In Collaborative discussions, some distinction was drawn between “harder” environmental benefits associated with some smart grid applications (e.g., reducing the number of combustion vehicles on the road as a result of PHEVs) and those that are “softer” (e.g., reduced emissions from power plants as a result of a shift in the load curve, and different generation dispatch, as a result of demand-response applications).

Recommendations

To the extent that they can be reasonably quantified (and that they can be attributed to the smart grid investment), environmental benefits should be quantified and monetized in the cost-benefit framework in the appropriate societal views/perspectives.

Any assumptions regarding environmental benefits incorporated in the analysis (e.g., emissions reduced, values of emissions/allowances) should be clearly stated and supported.

Monetization of Reliability Benefits

The overriding issue in the monetization of reliability benefits is in determining the appropriate value of reducing the frequency, duration, or scope of outages. Currently, the state of the art in reliability monetization (essentially, the cost of an outage) is based on customer surveys and their perception of the cost of outages of various duration. For example, in EPRI's *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*, the values from 28 customer studies from ten different utilities were consolidated.

- Typically, outage costs are not linear. There is a "fixed" component of any outage (which may be low or high, depending on the customer) and a "variable" component that also impacts the overall cost to the customer. The cost of an outage – and the relative cost of a short or long outage – will vary considerably based on the nature of the customer's activity or business.
- As with any survey, variability in results will occur based on the quality of the underlying survey instrument(s) and the understanding/sophistication of the survey-taker. This adds uncertainty with respect to the benefits that might actually result.

Another issue in monetizing reliability benefits is ensuring that the improvement in reliability associated with the smart grid investment is an improvement that would not have occurred otherwise. In other words, business as usual should not assume that there would be a degradation in reliability and may actually mean improvement, as older system assets are replaced with newer (but not smart) equipment.

Recommendations

Reliability benefits should be quantified and monetized in the cost-benefit framework in all of the appropriate tests, although the values could potentially be different for different tests.

A reasonable effort should be made to estimate reliability benefits separately for various groups of customers, since the cost of an outage could vary significantly based on the type of customer (and even for different customers within the same group). In this regard, the Collaborative contemplates perhaps three or four customer groups, and is not referring to the multiple rate classifications represented by the utilities' rate tariffs.

- Cost should be estimated for a minimal outage for the respective customer groups. The incremental cost of an extended outage should also be estimated in order to provide an indication of the impact of short and long outages on the respective customer groups.
- Reasonable effort should be made to estimate the permanent economic cost of an outage to various customer groups, including the following:
  - In cost terms for residential customers, who may sustain little or no economic impact from brief outages, but substantial damage from lengthy outages.
  - In profitability terms for business customers (i.e., the impact on a customer's profit as opposed to in general revenue terms).
- Because most reliability investments affect a combination of different types of customers associated with particular circuits, substations, or geographic areas, the use of a composite system average monetized reliability value would be appropriate in some cases.

To further guide potential reliability related investments (both smart and non-smart), the Collaborative recommends that the ICC sponsor an independent review of the available studies and data on the monetization of reliability benefits, and, if needed, conduct a subsequent Illinois-specific study (or studies) to determine the cost of outages on various customer groups in Illinois.

Monetization of Benefits Associated with Retail Generation Supply Prices

It is expected that a smart grid cost-benefit analysis will include, where applicable, an analysis of how the described benefits associated with demand response and efficiency programs could result in benefits to retail customers as a result of lower generation supply prices. These benefits may result when the smart grid demand response or efficiency program results in lower peak energy prices and/or lower demand for generation supply. Changing the dispatch of generating units, thereby affecting wholesale market prices, could benefit customers within the region, not just participating customers of the utility. The evaluation should project the extent of the demand response that is likely to occur as a result of one or more smart grid applications relied upon to justify benefits associated with lower generation supply prices. The magnitude of any effect on wholesale markets would depend on the extent of demand response by retail customers at any given time. Changes in the load curve could produce:

- Energy price mitigation. Reduced usage may result in lower real-time and short-term energy market clearing prices, particularly if the specific generation mix utilized to meet the adjusted load shape has a lower variable cost of production (largely fuel). The effect of reduced usage on market energy prices could be magnified during times when the transmission system is constrained, because congestion is a component of Locational Marginal Prices (LMPs). Reduced line losses due to smart grid functionalities (such as dynamic line rating) could add to the mitigation of energy prices, especially during times when the delivery system is constrained (and higher than average loss factors occur).

- Capacity price mitigation. In the long run, lower electricity demand may defer construction of generation and transmission and may lead to lower wholesale capacity market prices.
- Depending on the market and/or administrative mechanisms and policies employed by an RTO to set and recover energy and capacity costs, how power and energy are acquired in the market, and how these costs are allocated and recovered from retail customers by utilities and other providers, reduced demand could engender customer savings in the RTO region. The extent to which such effects can be monetized in the short run for customers will be dependent on the certainty and timing of projected reductions in load.

Estimating the value associated with the respective categories of benefits listed above can require complex models with numerous inputs and calculations. Depending on the types of benefits being modeled, simplifying assumptions and models can be utilized – making the number of inputs and calculations more manageable, while maintaining an acceptable level of precision. The type of model required is driven by the nature of the benefits that are being estimated:

- A system dispatch model could be utilized to evaluate the potential value associated with reduced production costs.
- Load flow studies could be performed under different scenarios to evaluate the potential value associated with lower congestion costs and line losses.
- A system planning model could be utilized to evaluate the potential value of deferring future generation and/or transmission investments.

The potential impact across a large system footprint raises issues surrounding which, if any, such benefits should be included in the analysis. Alternatives range from not including any such benefits, to accounting for only those benefits accruing to participating customers (when applicable), to all utility customers, to all affected customers in the state of Illinois, or to customers within the regional dispatch footprint (i.e., the ISO).

The extent of direct customer benefits from wholesale market effects depends in part on the procurement process for energy and capacity and how those costs are recovered from retail customers. The existence of long term wholesale energy procurement contracts on behalf of retail customers (such as contracts supporting the IPA procurement process) and other factors (e.g., load profile changes insufficient to change procurement products or strategies) could serve to limit or defer the realization of expected benefits associated with changes to the load curve that would otherwise accrue to retail customers. This is especially true in cases where the pricing of wholesale contracts during the contract term is unaffected by changes in the wholesale price of energy.

Recommendations

The estimation of potential benefits associated with changes in load shape should be accompanied by a discussion of the methodology and assumptions used in deriving the estimates. This discussion should describe the model(s) used, model inputs and outputs, model logic (at a high level), scenarios performed, and how model results are to be interpreted.

Benefits from changes in the load shape should be limited to those that are expected to accrue to electricity consumers in Illinois. Benefits expected outside the state can be noted, but should not be included in the cost-benefit analysis except in support of a Societal Test.

Monitoring and Verification of Results

This section contains Collaborative discussions and recommendations on issues related to monitoring and verification of expected costs and benefits

Given the magnitude and uncertainty surrounding some potential smart grid investments, as well as the likelihood that such investments may take place over an extended period, it may be appropriate to provide for an ongoing evaluation of smart grid investments following Commission approval and implementation. Ongoing evaluation could confirm that actual costs and benefits are in fact reasonably consistent with those estimated in the cost-benefit analysis, and could develop more accurate estimates for future analyses. Monitoring and verification can potentially identify flawed initial assumptions and provide for modification of smart grid deployment, planning, and implementation. It may be possible to structure implementation of some large smart grid investments in phases so that results can be confirmed on a smaller scale prior to full-scale implementation. However, it should be recognized that, with some smart grid investments, the realization of benefits may take an extended period of time to develop. The timing of estimated benefits (and costs) should be reflected in the cost-benefit analysis. How and when to assess the prudence of smart grid investments for regulatory purposes is a separate and distinct issue for the Commission to evaluate.

This document does not reflect any consensus or recommendations with respect to linking utility cost recovery to actual predictive results.

Recommendations

The Commission should periodically evaluate if the projected costs and benefits associated with an approved smart grid investment are being realized for customers, the utility, society, and/or other stakeholders prior to approving similar future investments.

The cost for monitoring and verification of benefits should be included as part of the investment/operations costs when evaluating the smart grid investment.

Large smart grid investments should be structured for implementation in time-phased stages, for evaluation purposes, if doing so does not have a significant deleterious impact on the economic viability of the investment. Structuring investments in this manner may facilitate the verification of benefits and provide opportunities for cessation of investments in the event that initial assumptions and estimates of cost/benefit prove to be inaccurate; thereby minimizing the potential for future stranded investments.

Post-implementation evaluations of smart grid investments should be based on the initial cost-benefit analysis approved by the Commission.

Utility Filing Requirements for Smart Grid Investments

Scope and Objectives

Utilities seeking cost recovery in the State of Illinois must provide supporting information to the Commission as part of their filing. For traditional (general rate case) filings, supporting information requirements are well established. However, the filing requirements associated with non-traditional (that is, any type outside a general rate case) cost recovery have not been defined. This chapter presents recommendations for supporting information that should be provided by a utility as part of a filing seeking non-traditional cost recovery in the State of Illinois for smart grid investments.

Although Collaborative stakeholders were able to agree on the general nature and content of these filing requirements, there was fundamental disagreement among stakeholders about how "filing requirements" should be interpreted.

One group of stakeholders believes that the filing requirements identified in this chapter should be mandatory requirements. Although this group views filing requirements as mandatory, they also believe that a utility should be allowed to request a waiver for any requirement that the utility believes is not applicable or relevant to its smart grid cost recovery proposal.

A second group of stakeholders is concerned with the potential consequences of not meeting one or more of the filing requirements should these requirements be viewed as mandatory. This group of stakeholders believes that the "filing requirements" should be viewed as guidelines or informational requirements for utilities to use in determining the issues to address and information to provide in or at the same time as their filings, but not as legal requirements that could be a grounds for dismissing or striking a filing (i.e., not a formal pleading requirement) nor be substantively determinative of any Commission's decisions as a matter of law. Those stakeholders supporting a "guideline" approach would generally condition or limit application of a filing requirement based on whether it would be unduly burdensome to comply with that requirement, and would limit informational filing requirements to situations where the information is available to the utility (i.e., in general, not an obligation to create what does not already exist or obtain what is not in its custody or control).

While these groups of stakeholders ascribe to two different interpretations or definitions of "filing requirements" – mandatory requirements versus guidelines -- the Collaborative was generally in agreement on the scope and content of the filing requirements for non-traditional cost recovery of smart grid investments. The filing requirements identified in this chapter are grouped into the three categories:

- Cost-Benefit Requirements
- Technical Requirements
- Cost Recovery Requirements.

Filing requirements for the first two categories have been extracted from and are informed by the Cost-Benefit Framework chapter and Technical Characteristics and Requirements chapter of this Report, respectively. Cost Recovery Informational Requirements were identified separately from and are in addition to the cost-benefit and technical requirements.

Cost-Benefit Filing Requirements

The cost-benefit filing requirements have been extracted from the Cost-Benefit Framework chapter of this Report. The Collaborative was able to achieve consensus on these general requirements.

Cost-Benefit Filing Requirements	
Requirement	**Additional Information**
1. Provide cost-benefit analyses of the investment(s), including a Total Resource Cost test:	The analysis should include any factor (i.e., cost or benefit) that meets the following criteria: • They can be expected to have a meaningful economic impact on the utility's investment decision or are relevant to the Commission's approval decisions • They can be reasonably and transparently quantified and monetized • They are relevant to the analysis, specifically including the costs of achieving claimed benefits. Costs and benefits should only be counted once; there can be no double-counting of benefits. All costs and benefits used in the analysis should be incremental to the investment when compared with a baseline or "business as usual" scenario. The baseline scenario should reflect the related costs or benefits that would be anticipated if the investment were not made. The cost-benefit analysis should recognize as a separate line item any stranded costs that would result from the smart grid investment. The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analysis to be filed with the Commission. • A Total Resource Cost perspective for investments should be presented by the utilities – both with societal costs and benefits and without societal costs and benefits • Other perspectives that should be presented include a Ratepayer Impact view (depicting how rates would be impacted) and a Customer/Participant view (depicting the impacts of customer-specific costs and benefits) As appropriate to each test, the cost-benefit analysis should separately identify: 1) Those costs and benefits that will be directly incurred or realized by ratepayers through the traditional ratemaking structure 2) Those costs that can be expected to be incurred by non-utility parties 3) Those benefits that will flow, if at all, through the wholesale price of energy or other markets

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4) Those benefits associated with broader societal objectives or results that are not necessarily reflected in regulated customer rates.

Cost-benefit analysis may bundle or package together investments in several applications if those applications are needed to function together or provide otherwise unachievable synergies, or if they are reliant on a common infrastructure investment.

To the extent that it is feasible to separate underlying platforms from individual applications, smart grid applications contained within a package should still be subject to individual cost-benefit analysis based on their stand-alone incremental costs and benefits.

Cost-benefit analysis should provide a calculation of a payback period based on the present value of the annual cash flows of the smart grid investment or package

Potential non-regulated, third party, or incidental revenue from smart grid infrastructure investments should be reflected in the cost-benefit analysis.
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<tr><td>2. Provide documentation supporting the cost-benefit analyses</td><td>

Documentation of key assumptions underlying the analyses, particularly of those factors that may have a high degree of variability and/or uncertainty
Discussion of the uncertainties associated with estimates of costs and benefits over the term of the payback period
Discussion of the potential change in benefits and costs that may occur over time assuming various implementation schedules
Identification and discussion of other investments or approaches (if any) that reasonably might achieve similar or better results
Documentation of the discount rates used in the analyses and a discussion of the rationale for their use
Documentation of a sensitivity analysis of the projected costs and benefits of the investment to variables and assumptions. While reasonable discretion should be provided in terms of the variables and assumptions to be included, the sensitivity analysis should:

Identify the key variables from the cost-benefit analysis that merit sensitivity analysis. The degree of participation, assumed behavioral impacts, and persistence of customer behavior changes should be among the variables included in sensitivity analyses. Other candidates for inclusion are variables (such as emission costs and reliability) that have a wide range of potential values and/or are more subjective in nature.
Produce cost-benefit results using alternate values for the variables in order to demonstrate the sensitivity/impact various scenarios might have on the economic profile of the smart grid investments.

Discussion of the rationale behind the packaging or bundling of applications in the analyses
Documentation of the investment’s useful life and the basis for its determination
Documentation of the length of time over which reasonable customer benefits can be reliably estimated
Documentation of assumptions regarding any environmental benefits incorporated in the analysis (e.g., emissions reduced, values of emissions/allowances)

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	• Discussion of the methodology and assumptions used in deriving the estimated benefits from load shape changes. This discussion should describe the model(s) used, model inputs and outputs, model logic (at a high level), scenarios performed, and how model results are to be interpreted.

Technical Filing Requirements

The technical filing requirements have been extracted from the Technical Characteristics and Requirements chapter of this Report. The Collaborative was able to achieve consensus on these general requirements.

Technical Filing Requirements	
Requirement	**Additional Information**
3. Provide a description of each smart grid application included in the investment and a discussion of the technical design of the application	• Discussion of technical design should include utility plans to address each of the following design issues: – Capacity, including the factors of latency, data volume, and event rate – Technical Maturity and Risk o Identification of the criteria used to evaluate technical maturity and risk o Discussion of the measures that will be put in place to make it possible for the functions of the smart grid components to continue to be maintained and supported – Openness and Standardization o Identification of specific standards used in the technology to be deployed o Discussion supporting why any of the following types of standards, technologies or specifications are used: ▪ those that are proprietary or non-standard ▪ those requiring royalty fees ▪ those not listed in the NIST Interoperability Framework o Discussion of the level of interoperability required for the application o Description of utility's plan to ensure that there are published specifications for the applicable customer end devices and third parties to communicate with the utility – Security o Discussion of application security, addressing the following questions: ▪ How is the data protected from eavesdropping (confidentiality)? ▪ How is the source and destination of data verified (authentication)? ▪ How is the data prevented from modification or loss (integrity)? ▪ Which NERC Critical Infrastructure Protection (CIP)

	requirements apply to this application? ▪ Which NIST security requirements apply to this application? [Note: This requirement does not ask that the utility identify security vulnerabilities. Only the general techniques, standards and methods used by the utility need to be described] – Manageability o Discussion of how the performance and health of the smart grid system will be maintained – Upgradeability o Discussion of how the system has been designed with sufficient capabilities and resources to adapt to future conditions, in particular those areas known to be barriers to expansion, such as disk space, memory space, bandwidth, processing power, and tools o Discussion of how the system will integrate with existing systems, if applicable, for each application – Scalability o If applicable, utilities shall explain why any application cannot be made available to all customers – Reliability o Identification of applications and functions that are critical during power failures, and discussion of the design choices made to ensure that they continue to operate – Interactivity with Customers • Discussion of technical design should provide answers to the following questions for each design issue: – How does the smart grid investment address this design issue for this application? – Does this design issue present a challenge for this application? If not, why not? If so, how is the challenge being addressed? – What is the basis behind the technology selections as they relate to cost and benefits? – Under what conditions will the requirements and the importance of this issue vary?
4. Provide confirmation and/or discussion of application-specific requirements, if applicable	**Advanced Metering** • At a minimum, the system shall permit a complete validated read of all meters 12 times a year within the normal monthly billing windows. • Customer usage and billing data shall be kept confidential and managed in conformance with regulatory policies regarding data access and data protection • The system shall retain usage data for the time required by regulations **Remote Connect/Disconnect** • The utility shall have a process defined for authenticating the identity of any customer requesting a service connection or disconnection • The electronic command to connect or disconnect shall be confidential, authenticated and checked for integrity • The meter shall confirm the connect or disconnect and report it with a timestamp to the meter data management system within the regular

	reporting interval • The system shall provide the necessary technical capabilities to meet the remote connect/disconnect requirements set forth by applicable laws and regulations. **Customer Prepayment Using AMI** • The prepayment control system shall have the capability to perform the following tasks if specified by policy and regulations: – Prevention of disconnection due to seasonal rules – Prevention of disconnection for medical reasons – Prevention of disconnection at the request of a third-party, other than through requests of law enforcement agencies using established procedures – Validation of payment and reconnection of service within periods defined by applicable laws and regulations. **In-Premises Devices for Energy Usage Data** • The utility shall explain whether security is established end-to-end between customer devices and the back-office systems, and if so, how • The customer device and the utility should be mutually authenticated • The utility systems shall be able to detect when a customer device has been connected and when it has been successfully authenticated and configured; information respecting customers' ownership and use of such devices shall be treated as confidential customer information. • Customer usage data transmitted to the customer device shall be confidential, authenticated, and checked for integrity • In order to fulfill its duty to ensure security, the utility shall specify the reasonable interface requirements for a customer device, including security considerations. The utility side of this interface shall conform to open standards and best security practices • The customer devices shall not have access to other customers' individual usage information **Customer Web Portal for Energy and Cost Data** • Customer usage data transmitted to the customer through the web portal shall be confidential, authenticated, and checked for integrity **Third Party or Government Use of Data** • The system must be capable of enforcing the security policy defined by laws and regulations regarding third-party access • The default for third-party access must be that all access to customer usage data is restricted • The system shall be able to provide customer usage reports for the length of time that are at least equal to data retention requirements set out in applicable laws and regulations **Pricing Information to In-Premises Devices** • The pricing information provided to in-premises devices shall be confidential, authenticated and checked for integrity • The customer's usage data when participating in a demand response program shall be authenticated, checked for integrity, and kept confidential • Pricing information shall be delivered reliably and accurately to in-premises devices • The utility shall be able to verify that the demand response event

	indication was received by the energy services interface (e.g. the meter) or a third-party provider. Ideally this verification should include the time at which the event notification was received **Direct Load Control** • The direct load control message shall be authenticated and checked for integrity • The customer's usage data when participating in a demand response program shall be authenticated, checked for integrity, and kept confidential • Direct load control messages and signals shall be delivered reliably. The utility shall be able to verify that the demand response event indication was received by the energy services interface (e.g. the meter) or a third-party provider. Ideally this verification should include the time at which the event signal was received **Automatic Circuit Reconfiguration** • The utility shall explain how they will keep auto-restoration commands secure **Dynamic System Protection for Two-Way Power Flows and Distributed Resources** • The knowledge of which equipment and which distributed energy resource is energized/de-energized is a critical safety issue. Latency shall be "non-real-time" or better (<30 seconds) for information regarding this status. • The utility must have a plan to address the issues of back-feeding and micro-grids with distributed energy resources **Dynamic Volt-VAR Management and Conservation Voltage Optimization** • Control signals shall be secured **Asset Condition Monitoring** • Alarm information from asset condition monitoring must be secure **Customer Distributed Resource Interconnection** • It shall be possible for a meter capable of performing net metering to be installed at any customer site **Wide Area (Phasor) Measurement** • If the phasor measurement data is used to operate controls, the data shall be confidential, authenticated, and checked for integrity **Wide Scale Outage Recovery** • The communication system shall be maintained during a wide-scale outage in order to permit wide-scale outage recovery to be performed **Enhanced Physical Security** • Enhanced physical security services shall be protected from eavesdropping, spoofing, and denial of service

Cost Recovery Filing Requirements

The Cost Recovery Filing Requirements do not appear elsewhere in the Report. The Collaborative was able to achieve some consensus on most, but not all, of the general Cost Recovery Filing Requirements.

Cost Recovery Filing Requirements
5. Provide current credit rating reports from Standard & Poor's, Moody's Investors Service and Fitch Ratings
6. Provide full set of bill impacts by customer class of anticipated smart grid expenditures
7. Provide changes to existing tariffs or proposed new tariffs in Word format
8. Provide a current cost of capital summary. Additionally, describe how capital expenditures will be financed by source, including a breakdown of capital supplied by investors (e.g., debt and common equity), customers (e.g., advances and contributions) and government (e.g., matching funds, tax credits, and direct loans). Please provide this breakdown in dollars and percentages
9. Provide all analyses performed regarding the rate of return requested in cost recovery proposal, including, specifically, the effects of any reduced risk attributable to any non-traditional cost recovery approved for the smart grid investment on the utility's rate of return
10. Provide forecasts of expenses and capital expenditures
11. Provide a list of reports relied upon by management when deciding to pursue the project and alternatives considered and the reasons for rejecting each alternative
12. Describe how the utility proposes that prudence and reasonable cost issues be handled
13. Describe the cost recovery mechanism proposed to recover smart grid costs. To the extent a utility requests an automatic cost recovery mechanism or formula as part of its tariff proposal, the utility shall provide an explanation with supporting financial documentation of why the mechanism is warranted, and why traditional rate case recovery of costs associated with the investment is not appropriate and the proposed cost recovery mechanism is more appropriate than others
14. Provide an explanation of how the proposed recovery mechanism appropriately reflects the causation of these costs by each customer class. In addition, some stakeholders believe that the utility should demonstrate that (to the maximum extent practicable, fair, and equitable) its cost recovery proposal matches the range of cost recovery burdens with the range of beneficiaries (cost-causers), for those benefits used to justify the investment. Other stakeholders believe that this additional requirement would be inappropriate as a filing requirement.
15. Provide anticipated rates under the proposed recovery mechanism with all supporting work papers
16. If incentive compensation costs are requested in rate recovery as part of the company's smart grid cost recovery proposal, the utility must provide (i) all related incentive compensation plans (ii) testimony demonstrating all ratepayer benefits of such plans (iii) testimony that includes a full quantification of the amount of incentive compensation expense rate recovery requested by ICC account, by year and for the project in total
17. Provide Excel files with working formulas for all above items, as applicable
18. An explanation of how it will assure that discretionary smart grid investment receiving the proposed non-traditional cost recovery treatment will not diminish investments necessary for adequate, safe, and reliable service mandated by the PUA.
19. An explanation of how the investments it proposes are distinct, for cost recovery purposes, from ordinary system modernization

The Collaborative discussed the possibility of modifying the existing filing requirements identified in 83 Illinois Administrative Code 285 ("Part 285"), which are the mandatory information requirements for public utilities in filing for an increase in rates. Three different views were expressed by Collaborative stakeholders in reference to the Part 285 filing requirements summarized as follows:

One group of stakeholders contends that it is necessary for the utilities to provide all Part 285 information in order for parties to fully analyze all impacts of the cost recovery proposal. They point out that the specific nature and magnitude of a future smart grid cost recovery filing cannot be known in advance, and that financial information provided in accordance with Part 285 is essential to a determination as to whether any proposed extraordinary cost recovery mechanism is financially needed by the utility. These stakeholders contend it would be inappropriate to reject any or all of the Part 285 filing requirements in advance. This group feels that the Part 285 requirements should be maintained for non-traditional filings associated with cost recovery of smart grid investments. However, this group allows that some of the Part 285 filing requirements may prove unnecessary for particular future filings. In such case, this group of stakeholders recommends that the utility be allowed to request a waiver, with good cause demonstrated, of schedules that the utility believes are not applicable to its smart grid cost recovery proposal.

A second group of stakeholders contends that Part 285 was intended to apply to utilities seeking traditional cost recovery of smart grid costs and that these requirements, in the context of a non-traditional recovery filing, are excessive and burdensome, and would ultimately serve as a deterrent to a utility contemplating smart grid investments. In addition, the second group of stakeholders believes that these requirements may be legally incompatible with certain alternative cost recovery mechanisms.

A third group of stakeholders agrees that utilities should provide Part 285 schedules related to its non-traditional smart grid cost recovery proposal. However, this group also contends that a subset of Part 285 schedules would not be applicable to any non-traditional filings associated with cost recovery of smart grid investments. This group recommends that the following schedules be excluded from smart grid filing requirements and, therefore, excluded from the need for submitting a waiver request.

- Section 285.2040 Schedule B-5.2: Property Merged or Acquired from Other Utilities
- Section 285.2045 Schedule B-5.3: Leased Property Included in Rate Base
- Section 285.2100 Schedule B-11: Property Held for Future Use Included in Rate Base
- Section 285.2105 Schedule B-12: Analysis of Activity in Property Held for Future Use
- Section 285.2110 Schedule B-13: Customer Deposits
- Section 285.2115 Schedule B-14: Budget Payment Plan Balances
- Section 285.3020 Schedule C-3: Sales Statistics

- Section 285.3065 Schedule C-6: Social and Service Club Membership Dues
- Section 285.3066 Schedule C-6.1: Industry Association Dues
- Section 285.3070 Schedule C-7: Charitable Contributions
- Section 285.3180 Schedule C-19: Property Taxes
- Section 285.3185 Schedule C-20: Local Taxes, Municipal Taxes, and Franchise Taxes
- Section 285.3300 Schedule C-27: Fuel Adjustment Clause Revenues and Expenses – Electric Utilities
- Section 285.3305 Schedule C-28: Fuel Transportation Expense – Electric Utilities
- Section 285.3310 Schedule C-29: Decommissioning Expense – Electric Utilities with Nuclear Facilities
- Section 285.3600 Schedule C-32: Non-utility Operations

Appendix A: Smart Grid Technologies

Smart Grid Technologies

The Collaborative prepared a catalog of technologies which could be expected to support smart grid applications. A description of each technology is followed by a listing of smart grid applications that the technology might support, as well as an assessment of the relative maturity of the technology and, where available, an indication of technology costs. Smart grid technologies in this section are grouped into the following five categories:

- End Point Technologies
- Line Technologies
- Substation Technologies
- Telecommunications Network Technologies
- Enterprise Technologies.

End Point Technologies

AMI Meters

Description

An Advanced Metering Infrastructure (AMI) is composed of many parts, the foremost of which are "smart meters". Smart meters are distinguished from traditional meters and automated metering reading (AMR) meters by the presence of:

- Two-way communications
- Interval metering capability
- Remote upgradability
- Tampering detection

Beyond the basic capabilities, smart meters can include:

- An integrated service switch
- Equipment for communications into an in-premises network
- Advanced measurement capabilities

Two-way communications

The communications pathway to the meter can be wired or wireless. When referring to the communications technology for a particular meter, generally what is discussed is the final network pathway that connects directly to the meter. Several different communications technologies are typically involved in connecting the meter to the utility's enterprise systems.

As an example, a smart meter might use a wireless radio to communicate to a data aggregation device mounted on a utility pole. The aggregation device could communicate to the utility's enterprise system using a wired or wireless connection that is independent from the smart meter's wireless network. Additionally, the utility may use different communication technologies in different parts of their service territory based on physical geography, meter density, building architecture and radio spectrum availability.

Interval metering capability

The ability to manage the grid intelligently is improved by the timely capture of consumption and demand data for individual loads. Interval metering records energy consumption and demand throughout the day providing support for time-based rates. Typical divisions are 60, 30 or 15 minute intervals. Some advanced application requirements include 5 minute or 1 minute intervals.

Remote upgradability

The capability to remotely update smart meters provides the utility with the means to add additional functionality to the meter, enable meters to support the future needs of various customer classes and ensure the long term security of the AMI system.

Tampering detection

When a human meter-reader is no longer visiting the site regularly, meter tampering becomes a greater concern.

Tamper detection and mitigation is accomplished by several different methods. Some solid-state meters have a hardware tilt detection switch. When the meter is removed from the socket, this hardware switch causes a flag to be set in the meter firmware that is transmitted to the utility the next time the meter is read. When this flag has been triggered several times without a corresponding utility-known reason, this is a clear tampering indication.

Another method for handling tamper detection is to always measure energy being consumed despite the apparent current flow direction sensed by the meter. Net metering is a metering method of allowing and accounting for current flow in either direction, from utility to customer or customer to utility. It is used mainly when on-site generation is present, but some forms may also be applied to detect tampering attempts when there is no known on-site generation. Yet another tamper-indicating measurement is the "blink", or momentary loss of voltage. This can be captured by the meter and communicated to the utility, and used as a quality of service indicator as well.

Integrated service switch

Many large utilities are choosing to install smart meters with an integrated service switch. Broad deployment of these switches combined with communication technologies will allow the utility to perform both service connect and service disconnect operations remotely, saving on utility personnel trips. Service connections and disconnections are coordinated by the utility's meter management software and are based on utility rules and policies.

The majority of AMI vendors are currently supporting a service switch rated at 200A maximum current. This is sufficient for most of the residential market and for some small businesses. Customers with larger current connections can be equipped with smart meters in different form factors, but those meters will not have service switches installed.

In-premises network communications

The ability for the smart meter to communicate into the customer's premises to a variety of devices is often a major rationale for the deployment of an AMI system. This network is often referred to as the home area network (HAN) but is not intended to be limited to residential customers as any residential or business customer can benefit from the ability to receive information from the smart meter.

The premises network technology can be wired or wireless depending on the meter vendor. Most large utilities installing smart meters are installing meters with this capability since it enables applications such as: providing energy usage information to the customer, providing energy price information to the customer, and a variety of demand response programs. A smart meter communicating into the premises can provide data to a variety of devices, including displays, thermostats, pool pumps, appliances, customer owned generation or energy storage and energy management systems. In addition to the meter providing data into the customer's premises some applications would entail customer devices providing data back to the utility or a third party or permitting remote control of a customer owned device by the utility or third party. Applications involving customer data or control require policies that protect customer privacy and safety interests.

Advanced metering capabilities

Power quality (PQ) is a prevalent topic in the metering industry. The measurements that are used to perform PQ calculations are starting to be specified for residential meters as part of smart grid rollouts. These measurements include voltage, voltage profile, current, and power factor, in addition to energy (kilowatt-hours) and demand (kilowatts). PQ performance measures such as total harmonic distortion (THD) and total demand distortion (TDD) can be calculated in the meter or in the utility back-office application for use in service assessments and complaint resolution. IEEE has standards for power quality characterization and power quality data transmission, such as IEEE 519 and the IEEE 1159 series.

Some meters can log voltage sags (below normal voltage) and swells (above normal voltage) with average amplitudes and durations for each event. Such logs are useful for guaranteeing compliance with ANSI C84.1 ranges and will be increasingly needed as voltage-regulation programs see more widespread use.

Applications

As seen in the table below, AMI meters are a required element of the AMI applications identified for this Collaborative. Additionally, AMI meters can be used to support a variety of additional applications by providing communications to customers or providing additional data to the utility.

Application	Support
AMI Applications	
Core AMI Functionality	AMI meter required
Remote Connect/Disconnect	AMI meter + service switch required
Outage Management Support	AMI meter required to provide outage notification
Power Quality/Voltage Monitoring at the Meter	AMI meter + advanced measurement required
Customer Prepayment Utilizing AMI	AMI meter + in-premises network capability required
Customer Oriented Applications	
In-Premises Device for Energy Usage Data	AMI meter + in-premises network capability enhances application. Non AMI solutions also exist.
Customer Web Portal for Energy and Cost Data	AMI meter required to provide interval data to the utility
Outage Notification to Customer	AMI meter enhances application
Demand Response Applications	
Price Information to In-Premises Devices	AMI meter + in-premises network capability enhances application. Non AMI solutions also exist.
Direct Load Control	AMI meter + in-premises network capability enhances application. Non AMI solutions also exist.
System Frequency Signal to Customer Load Control Devices	AMI meter + in-premises network capability enhances application. Non AMI solutions also exist.
System Renewables Output to Customers	AMI meter + in-premises network capability enhances application. Non AMI solutions also exist.
Distribution Automation Applications	
Dynamic Volt-VAR management	AMI meter enhances application
Conservation Voltage Optimization	AMI meter enhances application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	AMI meter enhances application
Enhanced System Modeling and Planning	AMI meter enhances application
Distributed Resource Applications	
Customer Distributed Resource Interconnection	AMI meter enhances application

Coordinated Management of Distributed Resources	AMI meter enhances application
Electric Vehicles : Optimized Charging	AMI meter + in-premises network capability enhances application
Dispatch of Electric Vehicle Storage	AMI meter + in-premises network capability enhances application

Costs

Costs for AMI meters typically range from $100 to $300 based on vendor, presence of a service connect switch, presence and choice of in-premises communications technology, advanced metering capability, memory storage requirements and meter form factor.

Since the cost of the smart meters themselves is only one component of an AMI system utilities often compare the total cost of their AMI system installation averaged across the total number of meters installed. This allows the utility to include other major cost elements of the AMI system such as the AMI network, utility enterprise systems required to operate the AMI system, development and installation costs. Average installed system costs for large utilities typically range from $250 to $350 per meter when averaged across very large numbers of meters.

Maturity

Advance AMI meters are a developing technology. The core functionality of smart meters is mature, having been proven in several large deployments and is an extension of proven AMR technologies. Smart meter functionality for in-premises communications is relatively mature, but continuing development is occurring and utilities are attempting to validate the various technologies. Robust security is another developing element for smart meters and is required to ensure the business value of an AMI deployment. Security is critical when considering smart meters with service switches or in-premises communications.

Electric Vehicle Charging Portal

Description

An Electric Vehicle Charging Portal (EVCP) consists of the following items:

- Electrical Outlet
- Energy Service Communication Interface (ESCI)
- End-Use-Measurement-Device (EUMD) or meter
- Electric Vehicle Supply Equipment (EVSE)

The electrical outlet is a basic electrical outlet at the customer premises. It allows for charging of any Plug-in Electric Vehicle. At a minimum, the energy portal should be a 120V, 15A outlet, but can also be a 240V electric vehicle supply equipment outlet connected to the premises circuit.

The End-Use-Measurement-Device (EUMD) measures and communicates energy usage information payload to the Energy Service Communication Interface (ESCI). The PEV EUMD will provide PEV charging session information: PEV ID and interval kWhr consumption. The Electric Vehicle Supply Equipment (EVSE) is the physical electrical cord and connectors that are specified by applicable SAE standards (SAE 2293, SAE 1772, SAE J2836, etc.) that provide a transfer of electrical energy from the energy portal to the PEV. This can be 120V or 240V AC depending upon the type and size of the energy portal. An EVSE may or may not have communication capability.

The Energy Service Communication Interface (ESCI) handles the information between utility, PEV, and End-Use-Measurement-Device (EUMD). The ESCI serves as the information gateway. The ESCI shall provide the PEV charging session information to the utility – PEV ID, interval kWhr consumption, time of kWhr consumption, etc. The ESCI passes from utility to PEV, the energy information including price signals and schedules, event messages, configuration and security data. This interface may or may not be facilitated by an Advanced Metering Infrastructure (AMI) Home Area Network (HAN). The ESCI can receive, record, display and transmit data, tariff data, consumption, etc. to and from authorized systems and provide other advanced functions based upon customer settable preferences.

Applications

Application	Support
Distributed Resource Applications	
Electric Vehicles: Optimized Charging	Electric vehicle charging portal required
Dispatch of Electric Vehicle Storage	Electric vehicle charging portal required

Costs

The cost of a complete Electric Vehicle Charging Portal installation can vary widely depending on the number of assets and communications infrastructure needed. Basic functionality may cost $150 for adding a smart meter to the customer premises to $500 for ability to control charging, set up charging schedules, automate demand response events and support a vehicle to grid capability.

Maturity

Electric Vehicle Charging Portal within the power system environment can be considered an emerging technology. There is a significant increase in utility activities to support second generation PEVs coming on the market. This has resulted in pilot deployments of EVCP technology in limited scope by some utilities. This will lead to significant, rapid product development and innovation. Integration with smart metering is underway.

IN-PREMISES DEVICE

Description

Enabling interconnection of key loads and information endpoints within the utility customer premises to the smart grid can help utilities maximize smart grid communications infrastructure investments and deliver societal benefit. Interconnecting home loads holds the promise of grid reliability enhancements, deferred power infrastructure investment, general conservation increase, carbon footprint reduction, consumption leveling, rate enhancements, and many others. Currently, utilities have little idea how customers use home loads in disaggregate, but have a good idea of what would be best for the grid if something about that load could change. Utility customers have no idea how the grid functions, but are directly impacted by a usage based cost they do not understand. Customers can currently mitigate their usage though home automation, but any existing automation technology is limited by a lack of awareness of grid conditions, customer preferences, or customer comfort. Endpoints, devices, and communicating automation are required to align the electric system needs to customer decision making.

Customers Understanding Premises Consumption Behavior

In-home display technology is the first step in augmenting the current consumption behaviors of customers. An AMI meter capable of reporting load changes down to the tenth of a watt with a 5% or better measurement precision can be an effective platform to provide the customer premises with data about every type of load or load group within their home and the impact of changing an appliance's state. Without a way to see the status of in-home consumption or the price of consumption, customers will not know how best to reach their own cost targets for their energy bill. The market is currently constructing ways to get that information to the customer. At some point, devices may be capable of measuring and disaggregating their own power consumption. Customers already have many types of displays within their home. Utilities are seeking to integrate with existing displays such as computers, televisions, and thermostats. In some markets, utilities are deploying brand-specific displays that match the communications media the AMI meter supports. Other utilities are deploying open IP based protocols into the home so that any existing or future display can interoperate with energy services.

Behavior Modification

Providing customers with consumption and price data is important, however, they must act on the information to benefit themselves and the grid. Energy management systems (EMSs) are the second step in augmenting customer behavior. An EMS can automate consumption management for well-understood customer led optimizations and preferences. Energy management starts with individual appliance automation and its human-machine interfaces. The role of the EMS can scale up to whole-home consumption management. An EMS can help the customer stay within spending limits, or to alert the customer about changing grid events and conditions. It is expected that common protocols will be available in the device market to coordinate utility interaction with energy management systems and end appliance automation.

Applications

Application	Support
AMI Applications	
Customer Prepayment Utilizing AMI	In-premises device is required
Customer Oriented Applications	
In-Premises Device for Energy Usage Data	In-premises device is required
Customer Web Portal for Energy and Cost Data	In-premises device may be enhance this application
Outage Notification to Customer	
Demand Response Applications	
Price Information to In-Premises Devices	In-premises device is required
Direct Load Control	In-premises device is required
System Frequency Signal to Customer Load Control Devices	In-premises device is required
System Renewables Output to Customers	In-premises device may be enhance this application
Distributed Resource Applications	
Customer Distributed Resource Interconnection	In-premises device may be enhance this application
Coordinated Management of Distributed Resources	In-premises device may be enhance this application
Electric Vehicles : Optimized Charging	In-premises device is required
Dispatch of Electric Vehicle Storage	In-premises device is required

Costs

According to some large appliance manufacturers, customers currently see little value in additional communications gear with current electric market conditions. In the near future the manufacturers expect that integrating smart grid communications with appliances and appliance interfaces will have a perceived value to the customer. Currently, specialized displays, and devices may have costs ranging from approximately $55 for a basic unit to $400 for a touch screen, fully integrated thermostat.

Maturity

Existing home appliances are very mature; some newer appliances (e.g. Refrigerators, washers, dryers) are extremely efficient relative to their counterparts of 15 years ago. The latest appliances merely add demand and price responsive behavior via a communications link. Other appliances such as water heaters (with several key exceptions) have not advanced very much. There are new grid-relevant home appliances and appliance configurations coming onto the market, especially in the field of energy storage and home-scale demand response that are both experimental and highly market-dependent. EMSs and their human computer interfaces are all very immature.

Line Technologies

Capacitor Bank Controllers

Description

A capacitor bank is a device a utility may connect to a distribution power line to adjust the total load on the line so more apparent or "real" power is used instead of reactive or "imaginary" power. A capacitor bank controller is the device that determines when it is necessary to switch the bank in or out of the circuit. It is typically located at the same site as the capacitor bank itself.

See Appendix A.1 for more information about reactive power.

The primary application for a capacitor bank controller is called Volt/VAR control, where VAR means "Volt-Amperes Reactive". When many customers on a feeder are using equipment such as large electric motors, air conditioners or electric furnaces, the load is said to be very "inductive" or "reactive" and there are a few possible results.

- The voltage on the line may drop significantly, causing customers with sensitive equipment to be affected.
- The apparent measured power and energy on the line will decrease. Utilities can only charge for the energy from apparent power. The reactive power adds to the system losses that are attributed to all rate payers.
- If there is too much reactive power used, the frequency on the distribution line can be affected which can lead to instability.

Capacitor bank controllers fall into three main categories: stand-alone, communicating, or centralized.

- A stand-alone controller makes the decision to switch in the capacitor bank on its own without any external help.
- A communicating controller may make its own decisions, but the settings for making those decisions can also be adjusted by a remote operator, or the operator may treat the controller as a remote manual switch.
- A centralized capacitor bank control system places all the decision-making capability at a single central site, for instance the nearest substation. It measures feeders through remote sensors and operates the capacitor banks through remotely-controlled switches that often have no decision-making capability of their own.

Capacitor bank controllers may use a number of different factors to determine when to switch in the capacitor bank.

- Power Factor
- Voltage

- Frequency
- Temperature
- Time-of-year
- Day-of-week
- Time-of-day

The ideal solution is that the controller measures both current and voltage, calculates power factor as a ratio of apparent power to reactive power, and switches the capacitor bank in or out of the circuit based on a power factor threshold. However, measuring power factor directly can be relatively expensive. To be most effective, utilities must deploy a large number of capacitor banks. Therefore the cost of each individual capacitor bank controller is a critical consideration.

Other capacitor bank controller solutions represent cost reductions of this ideal case. Instead of directly measuring power factor, the controller estimates the need for the capacitor bank by measuring voltage, frequency, temperature or time. It assumes that reactive loads are occurring if voltage or frequency drop too low, if temperature is too low or too high requiring much heating or cooling, or assumes that reactive loads occur regularly in certain seasons, days of the week, or times of the day. Such approximations can often be very accurate depending on the characteristics of the customers and environment.

The most extreme example of such estimation is that some capacitor bank controllers are simple clock-work timers that switch the capacitor bank into the circuit during peak heating or cooling hours of the day, regardless of the actual temperature or load.

Applications

Application	Support
AMI Applications	
Power Quality/Voltage Monitoring at the Meter	Capacitor bank controllers can use the data provided by AMI meters to improve switching operation decisions
Distribution Automation Applications	
Dynamic Volt-VAR management	Capacitor bank controllers required
Conservation voltage optimization	Capacitor bank controllers required
Distributed Resource Applications	
Coordinated Management of Distributed Resources	Capacitor bank controllers could be operated as part of the coordinated management scheme

Costs

The cost of capacitor bank controllers varies widely depending on the functionality provided. A flexible software-controlled system with multiple sensors may cost as much as $1000, while a clock-work timer may be less than $100. In addition to the cost of the controller, a significant cost of deploying a Volt/VAR control system is the cost of the switches used, which must be capable of connecting and disconnecting the bank from the feeder while it is live.

A traditional cost barrier to more advanced solutions has been the expense of communications. Current industry plans are to utilize AMI or other smart grid communications networks to support capacitor bank controllers.

Maturity

Capacitor bank controllers are an extremely mature technology. Although some vendors have recently produced advanced algorithms for predicting the need for the capacitor bank ahead of time, very simple solutions can often provide satisfactory results. The key issue in selecting a controller is determining the tradeoff between cost per unit and the flexibility and accuracy desired.

Dynamic Line Rating Sensors

Description

The first step in achieving dynamic ratings for transmission lines is to monitor the actual thermal condition of the lines using a range of sensors. The type of line sensors discussed here are used with traditional overhead power lines using bare conductors to assess the thermal capacity of the lines. The loading of transmission lines may also be limited by the stability limit for the system which can be monitored using synchrophasor measurement. From a thermal limit perspective, operators are challenged to maintain reliable use of the lines, not damage the lines and maximize the amount of current carried. In the past, the industry practice has been to use a fixed value for the current carrying capacity of the lines calculated using on an industry standard (such as IEEE 738). It is common practice for a utility to establish one or two fixed seasonal ratings such as summer and winter. However, the use of fixed values often results in unnecessarily low or under-loaded limits on the lines. At other times the fixed values may, in fact, result in an overload condition. Factors such as line materials, outside temperature, wind direction and speed, sunlight direction and intensity and the density of the air have a large impact on the actual carrying capacity of the lines.

A range of sensors and monitoring devices may be used to assess the condition of the lines such as tension and sag monitors, temperature sensors, weather monitors and integrated systems. In addition, communications equipment and software applications are necessary to deliver the data to the utility personnel that need it.

The motivation of monitoring the lines is to reliably and accurately determine the thermal condition of the lines in real time and to deliver that data to the utility supervisory control operators that are making line loading decisions. Access to this real time data allows the utility operators to establish a dynamic rating for the carrying capacity of the lines based on the measured condition of the line. Software applications can also be used to automatically inform the operators of the current and projected capacity of the lines. It may also be useful to implement real-time condition monitoring and dynamic rating of the associated power transformers in substations.

Example uses for dynamic line ratings include:

Response to Transmission Line Constraint

- Transmission constraint situations can be caused by a range of events such as an outage at a power plant or loss of another transmission line. However, if the operators are provided continuous line condition and capability ratings, there is a high probability that more capacity could be utilized on the available lines for periods of time. This might allow a reduction in the use of higher cost generation at a significant savings.
- If local generation is not available or not sufficient to make up for the reduced capacity, then the ability to carry higher loads may reduce the amount of load that must be shed and thus the number of utility customers impacted.

Real-time Adjustment of Line Loading Limits

- Fixed seasonal transmission line ratings are often determined on a conservative basis allowing a 1-3% risk of exceeding the line's design temperature if the line were continually operated at its rated current.
- Studies have shown that the impact of this approach is that 95%[45] of operator actions to reduce the load on lines are either unnecessary or excessive.
    - Real-time monitoring of lines can provide the operator key information such as:
    - Is the planned action necessary?
    - How large of a change in loading is needed?
    - When is the change needed and why?
- It is interesting to note that NERC plans to revise the Facilities Rating Standard FAC-008-2 to incorporate an optional real time facility rating.

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[45] Tapani O. Seppa, Chair, Joint IEEE & CIGRE Task Force, CIGRE TB 299, Guide for Selection of Line Ratings. (T. Seppa also consultant with Valley Group)

Avoidance of Line Clearance Violations

- Real-time alarms can give the operator advance warnings of possible line sag into trees and other objects and indicate how soon corrective action should be taken.

Deferred Construction of New or Upgraded Line

- Dynamic rating and continuous monitoring of lines can enable sufficient additional line capacity to allow the deferral of expensive capital projects.

Ice Monitoring and Mitigation

- Real-time monitors can be used to warn of dangerous ice conditions, monitor effectiveness of ice mitigation and realize cost savings by only heating lines when required.

Figure 1 shows an example of the additional available line capability vs. a static rating and how a period when the actual capability was less than the static rating.

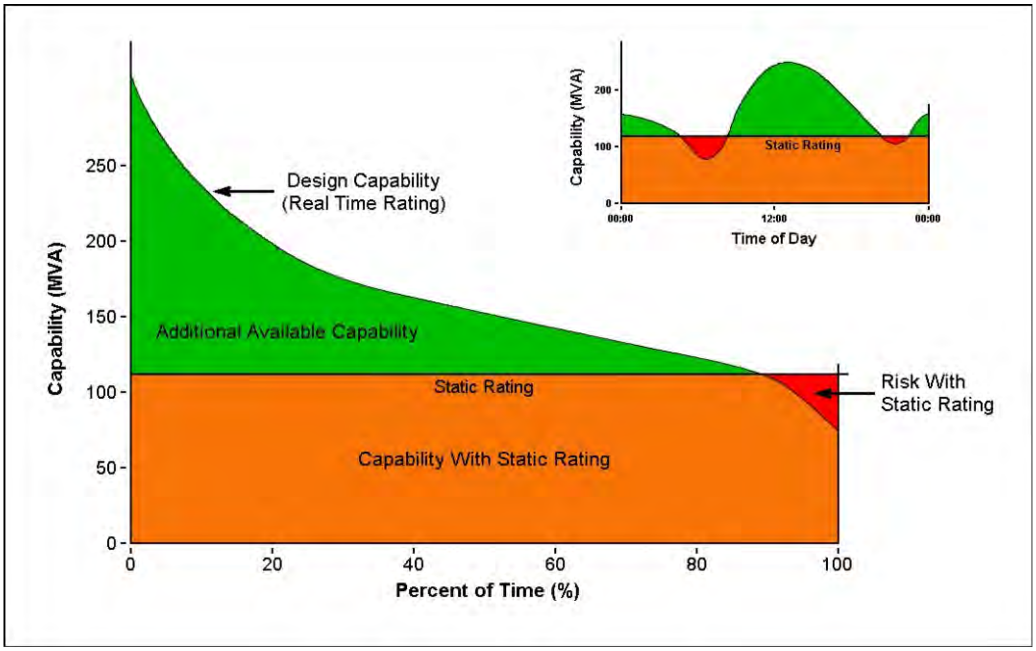


Figure 1: Comparing Measured vs. Static Line Ratings (Courtesy of EPRI)46

[46] DOE Modern Grid Initiative: "A Systems View of the Modern Grid"; Appendix B2, Sensing & Measurement, March 2007

Applications

Application	Support
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Dynamic line rating sensors can be an element of this application
Asset condition monitoring	Dynamic line rating sensors can be an element of this application
Distributed Resource Applications	
Coordinated Management of Distributed Resources	Dynamic line rating sensors can be an element of this application
Transmission Applications	
Wide Scale Outage Recovery	Dynamic line rating sensors can be an element of this application

Costs

The range of costs for monitoring devices and systems varies quite widely. The cost for basic weather sensors can be in the range of $5,000 to $20,000 plus communications equipment for the data. Contract weather services covering a large region can provide some useful information at a reasonable monthly cost and may provide useful information for other purposes. Line tension monitors and video cameras used for monitoring line sag typically cost in the range of $20,000 to $30,000 per line segment plus communications. Integrated systems that monitor multiple line parameters may cost $80,000 to $200,000 per line depending on the length plus communications equipment. Software applications to interpret and display the line condition data are normally provided by the sensor suppliers. In addition, suppliers of Energy Management Systems (EMS) offer optional software for this application at a nominal cost.

Maturity

The adoption of transmission line monitoring sensors and systems has grown slowly but continually since the 1980s. While it is not a large market, the most prominent supplier of this equipment has installed hundreds of systems at over 50 utilities worldwide. Transmission congestion continues to be a significant issue in many regions, as is the difficulty in getting approvals to build new capacity; therefore it is likely that the pace of adoption will continue to grow. Depending on the type of sensors being used, thorough testing over a period of time is warranted due to the harsh and often remote locations for the equipment.

Fault Indication Devices

Description:

While protective devices will detect faults and trip a circuit breaker to protect the circuit, the failure must then be located and repaired. On overhead distribution lines, the line is often manually observed for failure, a sometimes time-consuming procedure. In order to reduce the time required to locate and repair, fault indicators are often placed in strategic locations along the line. The fault indicator is a magnetic or electronic device that signals the passage of excessive current through the line. Fault indication devices are single-phase, clamped around a single cable or overhead wire.

Magnetically operated devices turn an indicator from black to orange to indicate the passage of extremely high current. Electronic devices will light a lamp to indicate the same thing. These devices generally reset after hours of normal current in the line. If the fault indicator shows that current passed though that section of the line, then the next downstream device is checked. The section of the line that is faulted is then known.

A common arrangement is placing fault indication devices at either end of a section of aerial construction that passes through a wooded area with no adjacent roadway. Such areas would normally be patrolled on foot to find line problems. By placing fault indicators at the entrance to and exit from such areas, needless walking of the line can be eliminated.

Underground cable cannot be observed and faulted cables must be repaired by replacing the failed portion. Typically, fault indication devices are placed at junctions or a transformer in order that a quick check will indicate which portion of the cable has failed.

Distributed generation and generation in the distribution system will change the upstream/downstream nature of the utility distribution system. With fault current available from more than one direction, simple fault indicators will provide less information

Applications

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Fault indicators can be an element of this application
Improved fault location	Fault indicators can be an element of this

	application

Costs

Fault indicators cost hundreds of dollars. The value of the time saved in restoring service to customers may far exceed the value of the devices.

Maturity

This technology is very mature. New versions of the devices may be developed as electronics improve.

Fault Location Devices

Description

Knowing the construction of a line (conductor size, spacing, and length, for instance) permits the calculation of the electrical parameters of the line, including the resistance, inductance, and capacitance. When a fault or short circuit occurs, those parameters are changed – the line is effectively shorter during the fault.

Modern electronic systems can use the voltage and current measured on the line during a fault and calculate the apparent length of the line. The result is an approximate location of the fault.

Fault location is often a feature of modern digital relays. Dedicated fault location devices may be installed in substations. Transmission lines which are networked and allow power to flow in either direction may install or enable fault location at both ends. The two readings offer a good estimate of the location. That is invaluable when the cause of the fault is not readily visible, such as a cracked or dirty insulator.

Applications

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Fault location devices can be an element of this application.
Improved fault location	Fault location devices are required.
Dynamic System Protection for Two-Way	Fault location devices can be an element

Power Flows and Distributed Resources	of this application.
Transmission Applications	
Wide Scale Outage Recovery	Fault location devices can be an element of this application.

Costs

Fault location is available as a firmware option on many digital line relays. Dedicated fault location devices cost thousands of dollars.

Maturity

Fault location is based on the same principle as transmission line protection, or distance relaying. Because short circuits are cleared from the system very quickly, fault location became widely possible with digital protective devices, capable of making the complex calculations. The principles are well founded and the technology is offered by a number of manufacturers.

Feeder Switch Controllers

Description

Feeder Switch Controllers (FSCs) are a key component of a distribution automation programs and provide important data gathering and control capabilities on the feeder. An FSC is co-located with a distribution feeder three phase electrical switch that is either pole or pad mounted. The FSC's primary role is to collect measurement data, control the feeder switch and communicate with a remote Supervisory Control and Data Acquisition (SCADA) Master computer or substation automation system. Communications is normally accomplished with wireless technologies but may use leased lines or fiber cable if available. FSC devices must be designed to work in an environment that is very harsh with wide operating temperatures of -40C to +85C being a typical requirement.

One of the primary applications for distribution automation and FSC devices is automatic feeder sectionalizing and restoration otherwise known as Fault Location Isolation and Service Restoration (FLISR). In their most basic form, these systems detect a fault, determine its location, and open the nearest available switches (or fault interrupters) during a tripped state of the fault-clearing recloser or breaker. This isolates or sectionalizes the faulted segment from the rest of the feeder.

Then, after extensive validation, the system automatically closes switches to restore power to the unfaulted segments thus minimizing the impact of the outage to utility customers. Systems may be designed to operate in one of three modes or a hybrid of the following:

- Local peer to peer
- Substation based control
- SCADA master control

Regardless of the mode, the systems operate under the jurisdiction of the system operator, who is able to turn off automatic operation as necessary. When operating automatically, these systems provide the self-healing capability that is a key benefit of a smart grid implementation.

Other applications for FSCs may include capacitor control, volt/VAR control and conservation voltage control. In addition FSCs may be co-located with feeder recloser controllers to facilitate communications.

Applications

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Feeder switch controllers are required
Improved fault location	
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Feeder switch controllers are required

Costs

Basic FSC units purchased separately (without cabinets) will typically run around $2,000. Fully integrated units with batteries, full input output measurement capability including AC fault measurement, a radio and an outdoor cabinet may run up to $10,000.

Maturity

The basic FSC units have been in use since the early 1990's so most suppliers are on their 2nd or 3rd generation of products. New technologies include communications options such as wireless mesh radios and the software applications. Higher risk components have been the durability of the cabinets and the batteries.

Recloser Controllers

Description

Reclosers are circuit interrupters used in medium voltage distribution systems. They are generally rated for full load capacities to hundreds of amperes, such as 70 amps, 140 amps and such. They may be used in a substation as a less expensive alternate for a circuit breaker on a lightly loaded circuit. They are offered in single-phase and three-phase versions.

More commonly, they are found partway down distribution circuits where the load falls to lower amounts of amperes and the devices may sectionalize, or disconnect portions of the circuit. They are preferred to fuses, because they will automatically test and reconnect the circuit in the event of a transient short circuit.

The recloser controller may be hydraulic or electronic. The hydraulic versions use fault energy to force hydraulic oil through an orifice that causes the electrical contacts to open and charge a spring. The trapped oil returns to the reservoir and the contacts reclose after a number of seconds. If the fault current returns, the cycle is repeated. The timing of the tripping and reclosing can be adjusted by altering the path of the oil. Typically, the recloser controller has inverse time tripping characteristics, tripping faster for higher fault currents. The reclose time is usually fixed at perhaps two seconds, an adequate time for lightning gasses to dissipate or wind to die down. Electronic reclosers may offer “open” times to 100 milliseconds to 600 seconds.

The electronic recloser equipment performs the same functions. The timing is done electronically and the closing is done electrically instead of a charged spring. The timing may be more precise and the system may require batteries.

Applications

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Reclosers can be an element of this application
Improved fault location	Reclosers can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Reclosers can be an element of this application
Transmission Applications	
Wide Scale Outage Recovery	Reclosers can be an element of this application

Costs

Electronic recloser controls cost several thousands of dollars and are available from several manufacturers.

Maturity:

Distribution reclosers have been in use for many years, starting with the hydraulic versions. Electronic versions were in use in the 1970s and were powered by NiCd batteries. With today's better battery technology and improved circuit interrupting mechanisms, the electronic reclosers and the controllers are reliable and well-accepted.

Substation Technologies

Asset Condition Monitoring Sensors

Description:

Most equipment in smaller substations today is unmonitored. That is, there is no instrumentation to tell operators or maintainers what is going on with the equipment. Currently, determining when to maintain or replace a piece of equipment is done by visual inspection or formula. In some cases temporary instrumentation is installed to determine the performance of the equipment for a short period of time.

The goal in a smart grid is to be able to monitor equipment to determine the status and performance of the equipment both to prevent outages and to prevent unnecessary trips to the substation. To do that monitoring equipment can be installed on existing equipment or specified in any replacement or new equipment. These sensors are mostly passive and are not attached to controls in the substation making them low risk from a security standpoint.

Examples of this type of equipment include:

- Voltage monitors on transformers and lines to determine what the input and output voltages are for equipment. This can provide early warnings of breakdowns in insulation in transformers and with the growing use of distributed energy resources, help point to voltage issues on different phases in the grid, which can waste energy.

- Temperature Sensors on transformers, lines and other equipment to determine both the current temperature and the rate of change in the temperature. These can be used to find equipment that is overheating or is responding improperly to increases in power consumption. Both conditions can result in outage and excessive losses in power.

A large number of other sensors can be added to substation equipment depending on the conditions that need to be monitored and the age of the equipment in the substation. In many cases the reduction in visits to the substation and the improved operator confidence in the equipment can result in less possibility of outage and the ability to support greater loads when needed.

Sensors are one of the lowest cost steps that can be taken as part of smart grid deployments and offer one of the lowest risk deployments possible.

Applications

Application	Support
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Asset condition monitoring sensors may enhance this application
Asset condition monitoring	Asset condition monitoring sensors are required
Enhanced System Modeling and Planning	Asset condition monitoring sensors may enhance this application
Transmission Applications	
Wide Scale Outage Recovery	Asset condition monitoring sensors may enhance this application

Costs:

Asset condition monitoring devices typically cost several hundreds of dollars and are available from many manufacturers.

Maturity:

Condition monitoring devices are a mature technology. Newer assets may incorporate some capabilities of standalone condition monitoring and reduce the need for separate devices.

Data Concentrators

Description:

In many substations today, each sensor or control is on its own phone line with its own modem. This ensures that only one sensor or control will stop working if there is a communication line failure and that there will be no issues with different devices trying to send information at the same time. The downside is that as the number of controls and sensors increase, the number of phone lines also has to increase.

Add to that the phone companies are doing less maintenance on their old copper phone lines, including reducing the number of different routes that data can travel, increasing the chances that a single failure of a phone cable would cut all of the data lines to a substation. In the 1970s technology required this type of installation and the utilities became very comfortable with this design. The net result is increasing monthly costs for data transmission from substations to the control center.

In the 1980's the data networking industry developed a set of devices that could route traffic from multiple sources on a single line. While some of this technology was installed in substations, mostly it was not. In the late 1990's traffic prioritization was developed, allowing rules to be written that would allow important data to jump the queue and go first. It was this step that allowed the routers to be more useful for utilities in substations and other outlying locations. Over the last decade, the networking industry has developed physically hardened versions of these devices for the military and they are now introducing them to the utility industry. Now a single line might contain data from several instruments and that means that use of a microwave system, a radio based system, a fiber optic system or other advanced communication system can either back up or replace the existing phone lines, improving the reliability of sending the data from one location to another.

Previously the need for so many individual channels made alternative methods cost prohibitive. Now with data concentrators, alternatives are more cost effective.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Data concentrators may be an element of this application
Improved fault location	Data concentrators may be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Data concentrators may be an element of this application
Dynamic Volt-VAR management	Data concentrators may be an element of this application
Conservation Voltage Optimization	Data concentrators may be an element of this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Data concentrators may be an element of this application
Asset condition monitoring	Data concentrators may be an element of this application
Enhanced System Modeling and Planning	Data concentrators may be an element of this application
Transmission Applications	

Wide Area (Phasor) Measurement	Data concentrators may be an element of this application
Wide Scale Outage Recovery	Data concentrators may be an element of this application

Costs:

Data concentrator devices can range from hundreds to a few thousand dollars depending on capacity and communications requirements.

Maturity:

Data concentrators are a mature technology.

FAULT AND DISTURBANCE RECORDERS

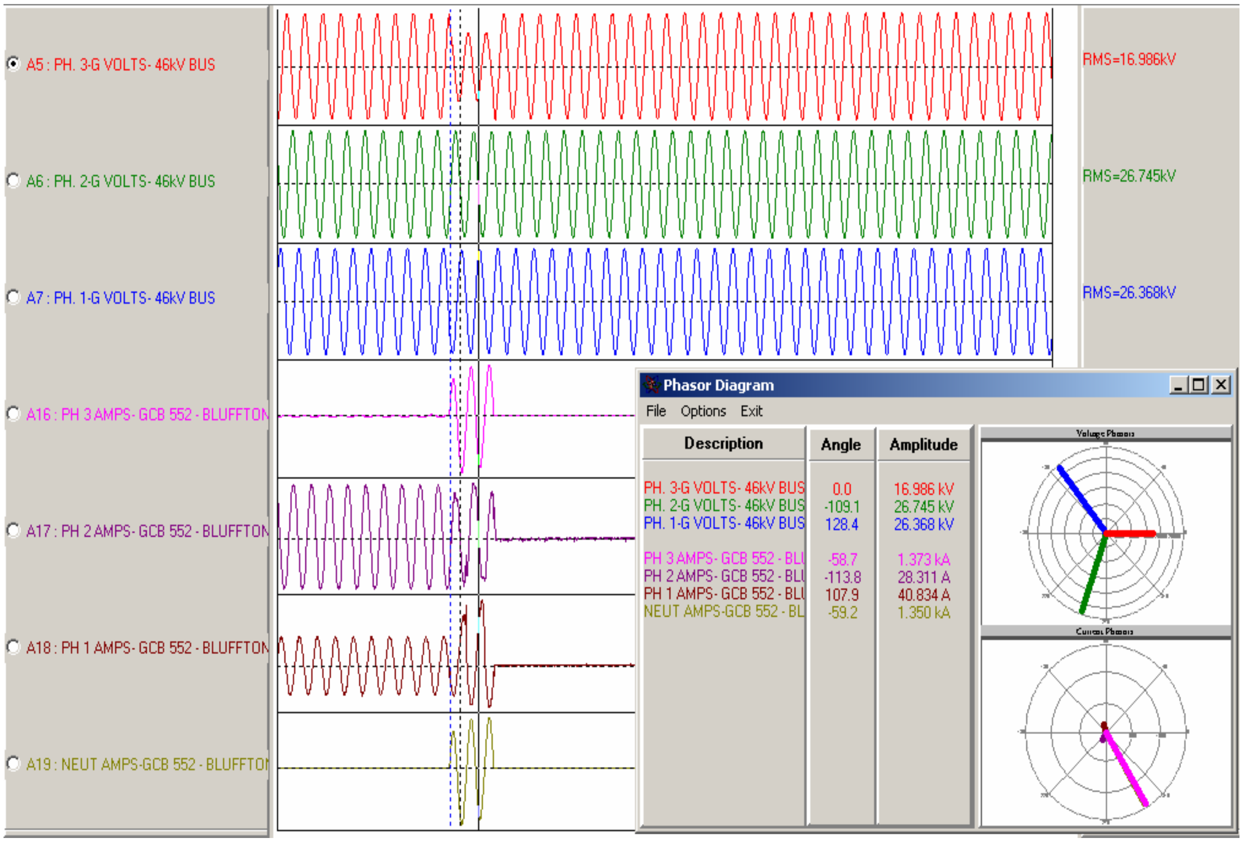
Description:

Fault recorders capture the voltage and currents associated with short circuits and other disturbances on the electrical system. They are connected to the same sensors that protective relays use and generally "take a picture" of the current and voltage waveforms that the protection system sees. An examination of that picture can affirm that the protective relays performed correctly.

The signals are digitized and continuously fed into memory. The memory discards the oldest data to make room for the newest data. When the system is triggered by a disturbance on the electrical system, active data recording starts. The memory allows the recording to include information about the circuits before the triggering occurred. This pre-fault data provides insight into the way that the disturbance evolved.

The systems may also include sequence-of-event recording capabilities. It is common for more than one protective relay to sense a disturbance, and it is useful to compare the order in which they react to the expected performance of the different systems. In the case of multiple events, such as both a transmission line and a generator tripping off at the same time, the order in which they reacted may lead to the revision of settings.

The fault recorder is typically applied at major transmission substations and generating plants. The most significant utilization of a fault recorder comes when a generating unit trips and there is conflicting evidence that the generator itself is damaged. The fault recording of the event will confirm or deny that the generator itself is damaged. With the operating value of generators and transmission lines equaling many thousands of dollars an hour, rapid assessment of the condition of equipment is critical.



A modern fault recording shows the voltages and currents associated with a short circuit on a transmission line. Examination of the recoding shows the magnitude and duration of the short circuit and which phases were involved. The recording would show evidence if the circuit breaker were not operating correctly and maintenance could be performed before it failed.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Fault and disturbance recorders can be an element of this application
Improved fault location	Fault and disturbance recorders can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Fault and disturbance recorders can be an element of this application
System and Asset Monitoring and Modeling	

Asset condition monitoring	Fault and disturbance recorders can be an element of this application
Enhanced System Modeling and Planning	Fault and disturbance recorders can be an element of this application
Transmission Applications	
Wide scale outage recovery	Fault and disturbance recorders can be an element of this application

Costs:

Fault recorders or circuit monitors vary widely in their capabilities. A unit capable of monitoring a simple office power circuit is available for a few hundred dollars, while a system to monitor the transmission circuits leaving a generating plant might cost tens of thousands of dollars.

Maturity:

The fault recorders of the 1950's were light-beam oscillographs making traces on photographic paper. Modern fault recorders are digital, making high resolution recordings of dozens of inputs simultaneously. The principle is quite mature and the technology has progressed from light-beam oscillographs through audio-style tape recorders to digital computers and memory systems.

Flexible AC Transmission System Devices

Description:

FACTS devices are a class of equipment the utility can install to improve the operation of the transmission system.

The Institute of Electrical and Electronics Engineers (IEEE) defines a ***Flexible Alternating Current Transmission System*** (FACTS) as "a power electronic based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability."

The complexity of the grid including its size, number and characteristics of individual components, physical configuration and electrical system characteristics provide real challenges to the optimum use of the grid. Additionally, transmission systems are undergoing continuous changes and restructuring due to such factors as transmission congestion resulting from load growth, market influences, integration of new renewable generation sources (ex., wind, solar) as well as encountering difficulties in obtaining regulatory approvals for new transmission lines and substations. These systems are becoming more heavily loaded and are being operated in ways not originally envisioned which is burdening the transmission infrastructure in a way that requires greater flexibility to react to more diverse load patterns and diverse generation sources.

FACTS devices are intended to meet some of these challenges to allow for optimization of grid operation and reduce the need for significant capital expenditures and negative environmental impacts associated with obtaining “rights-of-way” and construction of new lines and substations. Additionally, FACTS-devices provide a better adaptation to varying operational conditions, improves the quality of the power delivered, and maximizes the usage of existing infrastructure.

The discussion of these challenges will be focused on *why* a FACTS device is useful in a particular situation rather than a technical or theoretical discussion of *how* the device actually solves the problem. It is helpful to have a basic understanding of reactive power.

See Appendix A.1 for more information about reactive power.

Increase Transmission Capability

The amount of power that can be sent over a transmission line is limited. The origins of the limits vary depending on the length of the line. For a short line, the heating of conductors due to line losses sets a thermal limit. If too much current is drawn, conductors may sag dangerously close to the ground and/or other conductors, or equipment may be damaged by overheating. For intermediate-length lines on the order of 60 miles, the limit is set by the ***voltage drop*** in the line. For longer AC lines, ***system stability*** sets the limit to the power that can be transferred. FACTS devices such as series capacitors or phase-shifting transformers are used on long lines to improve stability.

Power quality

Getting as much active power as possible over the grid with a minimum of transmission lines, and a minimum of losses, are crucial tasks. However, the power which eventually reaches the consumer must also be of sufficient quality. Quality means that when we turn on the light at home, the voltage coming out of the socket should be fluctuation-free and free from harmonics, to make the flow of light smooth and comfortable, and free from intensity fluctuations. This, too, is a key task for FACTS to maintain. It is particularly important for residents living close to heavy industrial plants such as steel works, because such plants emit a lot of disturbances which spread over the electrical grid, which can effectively be remedied by FACTS.

Stability Improvements

Interconnected power networks can exhibit very complex dynamic phenomena when the system is disturbed from a steady-state operating condition. To complicate things even more, power systems are becoming more heavily loaded as the demand for electric power rises, while economic and environmental concerns limit the construction of new transmission and generation. Under these stressful operating conditions, transmission systems are subject to a variety of instability problems including voltage collapse, which has led to blackouts in electric utilities around the world. A variety of FACTS devices can be introduced into the transmission system that can counteract voltage collapse, and other transient issues. (See Table 2)

The benefits of utilizing FACTS devices in electrical transmission systems can be summarized as follows:

- Better utilization of existing transmission system assets
- Increased transmission system reliability and availability
- Increased dynamic and transient grid stability and reduction of loop flows
- Increased quality of supply for sensitive industries

Better utilization of existing transmission system assets
In many countries, increasing the energy transfer capacity and controlling the load flow of transmission lines are of vital importance, especially in de-regulated markets, where the locations of generation and the bulk load centers can change rapidly. Frequently, adding new transmission lines to meet increasing electricity demand is limited by economical and environmental constraints. FACTS devices help to meet these requirements with the existing transmission systems.

Increased transmission system reliability and availability
Transmission system reliability and availability is affected by many different factors. Although FACTS devices cannot prevent faults, they can mitigate the effects of faults and make electricity supply more secure by reducing the number of line trips (interruption). For example, in those instances where an over voltage of the line occurs, it can lead to a line trip. FACTS devices such as SVC's or STATCOMs counteract the over voltage and avoid line tripping.

Increased dynamic and transient grid stability
Long transmission lines, interconnected grids, impacts of changing loads and line faults can create instabilities in transmission systems. These can lead to reduced line power flow, or even to line trips. FACTS devices stabilize transmission systems with resulting higher energy transfer capability and reduced risk of line trips.

Increased quality of supply for sensitive industries
Modern industries depend upon high quality electricity supply including constant voltage, and frequency and no supply interruptions. Voltage dips, frequency variations or the loss of supply can lead to interruptions in manufacturing processes resulting in significant economic losses. FACTS devices can help provide the required quality of supply.

Applications:

The following table is not intended to be all inclusive of FACTS devices, but is indicative of many of the devices and how they may be applied to the transmission system.

Application	FACTS Devices
Increase transmission capability	
Improvement of stead state load sharing	Static VAR Compensator
Reactive power compensation	Static VAR Compensator Series Capacitor
Control	
Steady state voltage control	Static VAR Compensator Series Capacitor
Dynamic and post contingency voltage control	Static VAR Compensator Static Compensator
System stability	
System stability	Static VAR Compensator Series Capacitor Phase shifting transformer
Transient stability improvement	Static VAR Compensator Series Capacitor
Power oscillation damping	Static VAR Compensator Thyristor controlled series capacitor
Power quality	
Power quality improvement	Static VAR Compensator
Sub-synchronous resonance mitigation	Thyristor controlled series capacitor

Costs:

The transmission system is complex and requires analysis to determine which device is applicable to a specific system element and situation. Devices are typically a few hundred thousand dollars.

Maturity:

FACTS theory and technology has been around for a number of decades and devices are very mature. Due to the economic and environmental value of the devices however, there is an ongoing effort to improve the technology and its application in both the academic and manufacturing arenas.

Substation Computer

Description:

A substation computer is a platform by which the utility can tailor solutions for substation software applications to meet its specific needs. These devices differ from Intelligent Electronic Devices (IED), which can be considered a very specialized form of a substation computer. For substations computers, the operating system, applications, and hardware are independent from one another. This allows the utility to choose hardware, operating system, and applications from different vendors according to its needs. Makers can tailor-make substation computers to the performance requirements and budget considerations of the individual utility through the use of different processors and operating systems.

Substation computers are designed for computing applications that demand highest reliability and lowest maintenance in extreme, harsh environments. Since these computers often support mission critical substation applications, they offer increased reliability over standard computer hardware by eliminating all moving parts, including rotating hard drives and fans. They are designed and built to operate reliably in harsh environments, conforming to IEEE C37.90 and IEC 60255 Protective Relay Standards and the IEEE 1613 Standard for communications networks in substations. DC power supplies in these devices allow them to be powered directly from the substation battery and eliminate the need for an inverter to be used.

Microsoft Windows XP (both Professional and Embedded versions) and Linux are commonly used operating systems for substation computers.

While the potential applications for a substation computer are numerous, they tend to be tied to the utility's overall substation automation vision. Software can be custom written for a particular application or an off-the-shelf package supporting applications such as Human Machine Interface (HMI) or substation gateway/server. Often, the substation computer and its associated applications are part of a larger Substation Automation System (SAS) along with communications such as a Local Area Network (LAN) and substation Intelligent Electronic Devices (IEDS).

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Substation computers can be an element of this application
Improved fault location	Substation computers can be an element of this application
Dynamic System Protection for Two-Way	Substation computers can be an element

Power Flows and Distributed Resources	of this application
Dynamic Volt-VAR management	Substation computers can be an element of this application
Conservation Voltage Optimization	Substation computers can be an element of this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Substation computers can be an element of this application
Asset condition monitoring	Substation computers can be an element of this application
Enhanced System Modeling and Planning	Substation computers can be an element of this application
Transmission Applications	
Wide Area (Phasor) Measurement	Substation computers can be an element of this application
Wide Scale Outage Recovery	Substation computers can be an element of this application

Costs:

Due to the lower volume compared to consumer grade PCs, the costs for substation hardened computer hardware typically range from $5,000 to $10,000 per unit, including operating system. Applications which are loaded on these devices by the vendor or end users are not included in these figures and are typically purchased separately.

Maturity:

Substation computers can be considered a developing technology. While computing hardware is a mature technology, hardened systems suitable for substation have not been widely deployed by utilities mainly due to availability. These systems have only become readily on the market within the last 3 to 5 years.

Substation Controllers and Remote Terminal Units (RTUs)

Description:

This class of product has been referred to as Remote Terminal Units (RTUs) for many years. The original functionality of the RTU was focused on collecting substation data and measurements, executing control commands and communicating with Supervisory Control and Data Acquisition (SCADA) central master computers. Communication protocols and channels were generally proprietary and low speed serial. Since the 1980's, functionality has been incrementally added to most products including; communications to substation Intelligent Electronic Devices (IEDs) and feeder devices; sequence of events recording; data storage; basic metering; remote access and local automation functions. Communications has generally changed to standards based protocols and channels are either higher speed serial or Wide Area Networks (WANs) and Local Area Networks (LANs). The addition of functions such as these has resulted in this product class being called "Substation Controllers", Intelligent RTUs or "Substation Automation Systems". For the purpose of this Guide the term "Controller" will be used to describe this product class.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Substation controllers can be an element of this application
Improved fault location	Substation controllers can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Substation controllers can be an element of this application
Dynamic Volt-VAR management	Substation controllers can be an element of this application
Conservation Voltage Optimization	Substation controllers can be an element of this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Substation controllers can be an element of this application
Asset condition monitoring	Substation controllers can be an element of this application
Enhanced System Modeling and Planning	Substation controllers can be an element of this application
Transmission Applications	
Wide Area (Phasor) Measurement	Substation controllers can be an element of this application
Wide Scale Outage Recovery	Substation controllers can be an element of this application

Costs

Substation Controller or RTU products can vary greatly in price depending on the number of field points (measurement and control) to be connected and the features required. Very small point count units may cost $5,000 or less while systems with; many features; point counts in the thousands; a local PC Master; and redundant hardware and software can cost well over $100,000.

Maturity

This product class is very mature with most manufacturers producing their 3rd or 4th generation of products and systems. Current technology challenges include implementing the new substation communications standard IEC 61850, addressing cyber security requirements, handling the wide range of data types in the substation that go beyond traditional SCADA, enabling remote access to data and supporting a growing list of network communications technologies. As the industry addresses these technology challenges a transition is underway from the Substation Controller or RTU to system using a Substation Gateway and Substation IEDs (see descriptions in this Guide).

Substation IEDs

Description

The term "Intelligent Electronic Device" or "IED" is used to describe a piece of substation equipment that monitors and/or controls the operation of a substation using a programmable digital microcontroller or microprocessor. The term was originally coined to distinguish between these devices and older equipment that performed similar functions but used non-programmable analog electronics.

Early IEDs were dedicated to performing a single function. Today an IED usually performs multiple functions simultaneously. The table below lists several of the most common functions performed by IEDs.

Device/Function	Description
Meter	May measure and report a variety of basic power system quantities within the substation including: instantaneous, root-mean-square, and phase-to-phase or phase-to-ground phasor values of voltage or current; frequency; active, reactive and apparent power; power factor; energy; sequence; imbalance.
Power Quality Monitor	May measure and report a variety of advanced quantities having to do with the quality of power in the substation, including: harmonics and inter-harmonics of voltage or current; frequency; total harmonic or inter-harmonic distortion; time factor; K-factor; voltage crest factor; telephone

	influence factor; flicker; counts, time and frequency of root-mean-square measurement variations including sags, swells and interruptions.
Phasor Measurement Unit	Periodically measures voltage and current and their phase angle and reports the measurements to a central site for comparison. Refer to the corresponding description in this document for the functions provided by this type of IED
Fault Recorder	Captures and reports files describing the electrical waveforms and other events and characteristics surrounding the occurrence of a fault (short circuit).
Sequence of Events Recorder	Records and timestamps the occurrence of important events in the substation such as the opening and closing of switches and breakers, and the starting, stopping, and blocking of protection logic.
Protection Device*	Detects electrical faults and opens one or more breakers to protect equipment from damage. Any protection device using a microprocessor or digital signal processor is an IED. Refer to the corresponding description in this document for the possible functions provided by this type of IED.
Recloser*	Closes a breaker after it has been opened by a protection device, in order to recover from intermittent or transient faults on a circuit. Any recloser using a microprocessor or digital signal processor is an IED. Refer to the corresponding description in this document for the possible functions provided by this type of IED.
Programmable Logic Controller	Periodically evaluates a variety of measurements and switch positions within the substation and takes actions based on logic pre-programmed by a user. The programming mechanism may be proprietary or a standard such as IEC 61131-3. The actions taken by the controller may include adjusting settings of other automatic processes, or operating switches and breakers within the substation. One important application of this kind of controller is to enforce interlocking conditions that prevent users from performing unsafe switching operations.
Protocol Convertor / Gateway	Gathers data from multiple sensors or other IEDs and reports it to another device or computer system. It often reports the data using a different format than the format it received the data in. A protocol convertor or gateway is an IED by definition because these functions cannot reasonably performed by a "dumb" device. Refer to the corresponding description in this document for the possible functions provided by this type of IED.
Switch Controller	Arbitrates between multiple devices within a substation that wish to control a switch. Enforces interlocking logic to prevent users from performing unsafe switching operations. Synchronizes the opening and closing of the switch when the switch must be opened or closed in coordination with other switches, or must be opened or closed at a

	particular point on the electrical waveform.
Remote Terminal Unit	Reports the position of switches within the substation and may permit a remote user to control these switches. May also perform any of the other IED functions described in this list.
Asset Monitor	Measures and reports various quantities associated with the health of primary equipment such as transformers and breakers, including: arc counts; insulation level, temperature, pressure, density, moisture or flow; partial discharge counts or level.
Tap Changer Controller	Controls the output voltage of a transformer by automatically adjusting the position of the transformer tap to maintain a particular voltage as the load varies. May permit users to remotely control the tap manually, either by specifying its absolute position or by specifying a number of steps up or down from the current position.
Volt/VAR Controller	Controls the voltage and the proportion of apparent or “real” power to”Volt-Amps Reactive” or “imaginary” power supplied to a circuit by automatically switching one or more capacitor banks in or out of the circuit. Refer to the description of “capacitor bank controller” in this document for more details.
Automatic Generator Controller	Automatically adjusts the amount and frequency of electrical power supplied by a generator as the load placed on that generator varies over time. Gradually increases or decreases (“ramps”) the power supplied by the generator in response to requests from the market participant or operations departments of the utility.
Bay Controller	Performs multiple IED functions associated with a portion of a substation known as a “bay”, typically corresponding to a single transmission line, or feeder. May monitor, control and coordinate the functions of several other IEDs associated with that bay.
Battery Monitor	Reports the status (i.e. voltage level, charging or not charging) of the main substation battery or other batteries located in the substation.

Applications

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	IEDs can be an element of this application
Improved fault location	IEDs can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	IEDs can be an element of this application
Dynamic Volt-VAR management	IEDs can be an element of this application

Conservation Voltage Optimization	IEDs can be an element of this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	IEDs can be an element of this application
Asset condition monitoring	IEDs can be an element of this application
Enhanced System Modeling and Planning	IEDs can be an element of this application
Enhanced physical security	IEDs can be an element of this application
Transmission Applications	
Wide Area (Phasor) Measurement	IEDs can be an element of this application
Wide Scale Outage Recovery	IEDs can be an element of this application

Costs

The cost of an IED varies depending on the number of different functions it performs and the number of different pieces of substation equipment it is designed to monitor or control. A meter that monitors a single phase of a single feeder may be less than $200. A bay controller that serves as a meter, protocol convertor, switch controller, fault recorder and coordinator for several protection devices over all three phases of a feeder may cost $5,000.

Maturity

The maturity of IED technology varies based on the functions implemented. The most mature technologies are those associated with basic metering and control of switches. The least mature technologies are those that require more frequent measurement, prompt action and coordination with other devices. For instance, programmable logic is a mature technology, but there have been recent advances to make it easier to program and to reduce the interval in which the logic is evaluated. Similarly, metering is a mature technology, but increasing the frequency of measurement, accuracy of time synchronization, and decreasing the latency of reporting makes a meter a phasor measurement device and is considered much more advanced. Switch controllers are common, but the ability to perform synchronization and point-on-wave switching is more rare and costly. More advanced IEDs combine more functions in a smaller physical package, often with less power usage.

Substation Gateway or Data Manager

Description:

A substation gateway or data manager is a computer system that serves as both the primary collection point for data from IEDs or other devices within the substation, and the single point of access for controlling the operations of the substation from the outside.

A substation gateway or data manger may perform any of the functions listed in the table below. These functions are similar to those performed by a substation computer, and the terms are often used interchangeably. However, the distinction between a substation computer and a gateway is that a substation computer always has a graphical user interface and a gateway always provides external users with access to the substation data, while the reverse statement is not always true. In addition, a device capable of acting as a gateway qualifies as being called an Intelligent Electronic Device (IED) and may perform any of the IED functions described in the Substation IED device description.

Function	Description
Data Collection	Gathers data from multiple IEDs and other devices located in the substation. Typically stores this data in a "real-time" database that can spontaneously report changes to multiple users as they occur rather than having to be queried for the information.
Protocol Conversion	Converts message formats and semantics used by substation IEDs into those used by external computer systems such as Supervisory Control and Data Access (SCADA) masters, Energy Management Systems (EMS), graphical user interfaces (GUIs), historians and data warehouses, and vice versa.
Data Filtering	Limits the amount of substation information that must be processed by external users. Implements logic to merge multiple alarm conditions into a single alarm for simplicity of notifying a human user. Performs integration, threshold enforcement and trending on frequently changing values so spurious alarms are not generated. Continually reports to external users only a subset of all data gathered from the substation, but stores all the gathered data so users can manually request it if needed.
Bandwidth Management	Limits the volume of data exchanged within the substation so it does not exceed the capability of the communications links or the processing power of the gateway itself. May perform this function by not permitting devices to report data until they have been polled, by requesting data of lower priority less frequently than higher priority data, or by remotely controlling the thresholds and intervals at which IEDs will spontaneously report data.
Data Archiving	Maintains a sequential history of the changes to the data it collects, and permits multiple users to query this history. May store large data items such as fault records until they can be retrieved by external users.

	Automatically names and timestamps data for ease and accuracy of retrieval. Sometimes these functions are performed by a separate computer system known as a historian or data warehouse.
Data Protection	Provides a secure and reliable place to keep the substation data. Some of the technology used to ensure this reliability may include: ▪ Redundant power supplies ▪ “Hardening” of all inputs to be resistant to lightning and electromagnetic interference ▪ A real-time embedded operating system rather than a desktop computing environment. ▪ Non-volatile memory rather than spinning disks ▪ Real-time synchronization of data with a backup gateway or data manager ▪ Redundant lock-stepped processors ▪ Redundant communication links with the capability to detect failed links quickly ▪ Cryptographic protection of stored data ▪ Physical locks ▪ Damage-resistant case ▪ Resistance to environmental effects such as heat and humidity
Coordination	Serves as a central location for interlocking logic that prevents users from performing unsafe operations. Serves as a central location for protection logic that prevents a single fault from causing multiple breaker trips and therefore large blackouts. Synchronizes switching operations that are dependent on measurements from multiple IEDs. Automates sequences that require several switching operations to be performed in a particular order.
Access Control	Limits access to the substation data to only those who are authorized. Some of the technology used to ensure this access control may include: ▪ Providing the only physical electronic connections to the substation ▪ Requiring password authentication for access to IED data ▪ Requiring cryptographic authentication for access to IED data ▪ Acting as an application gateway, i.e. preventing messages from being relayed except through a local database ▪ Acting as a firewall router, i.e. relaying messages only if they satisfy configured rules ▪ Acting as a virtual private network (VPN) access point ▪ Acting as a terminal server, i.e. a network point of access to serially connected IEDs ▪ Providing a single location to manage passwords for all IEDs in the substation ▪ Encrypting data connections to substation IEDs or to external users as required

User Interface	Permits a user to monitor and control the substation using a mouse or touch screen and graphical conventions such as one-line diagrams, graphs, tables, lists and 3-D visualizations. May be connected to “mimic” panels having painted one-line diagrams, buzzers, horns, chart recorders, printers and annunciator displays of labeled light panels. May send alerts to human users via email, pagers, or text messaging. Provides all interfaces for multiple users simultaneously.
Time Synchronization	Serves the current date and time from an external time source such as a satellite receiver to IEDs within the substation.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Substation gateways can be an element of this application
Improved fault location	Substation gateways can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Substation gateways can be an element of this application
Dynamic Volt-VAR management	Substation gateways can be an element of this application
Conservation Voltage Optimization	Substation gateways can be an element of this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Substation gateways can be an element of this application
Asset condition monitoring	Substation gateways can be an element of this application
Enhanced System Modeling and Planning	Substation gateways can be an element of this application
Enhanced physical security	Substation gateways can be an element of this application
Transmission Applications	
Wide Area (Phasor) Measurement	Substation gateways can be an element of this application
Wide Scale Outage Recovery	Substation gateways can be an element of this application

Costs:

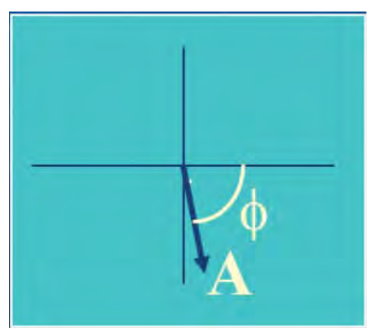
The cost of a gateway or data manager varies depending on the amount of data it must store, the reliability with which it must store the data, and the number of other functions it must perform. A simple data concentrator serving data from 8 or 16 serially connected devices to users connected via Ethernet might cost $5,000. A large system serving as a concentrator, security manager, user interface and historian for 200 or even 400 IEDs with hot standby and programmable logic might cost $30,000.

Maturity:

Maturity of gateway and data manager technologies varies depending on the requirements of the utility. Hardening of the computing platform, high-speed data collection and programmable filtering and logic are all very mature technologies, but there has recently been pressure from utilities to provide these functions on desktop computing platforms that users are familiar with and that they can load third-party software onto. This is risky and requires very expensive hardware to make up for the limitations of the operating system. Protocol conversion is a well-known technology, but new protocols such as IEC 61850 are challenging the structure of traditional databases. Cryptographic protection of data is common in the commercial computing environment, but traditional gateway providers are unfamiliar with the technology and again, more expensive hardware is necessary to perform the intensive cryptographic computation. There are a variety of methods that can be used to secure access to the substation, and no consensus among utilities on the best solution. Similarly, every utility seems to want to implement redundant data storage and communications links in a slightly different manner. Graphical user interfaces are not new, but previously these were typically supplied on a PC separate from the gateway, using proprietary software and another database. Lately they are expected to be web-based clients, served by the gateway itself, with no local storage of data at the client.

Phasor Measurement Units and Applications

Description:



The term “phasor” generally refers to high-speed, very accurately time-tagged data. The phasor data are actually “phasor quantities,” referring to the graphic means (See Figure) used to represent quantities having both magnitude (A) and angular position. Thus, phasors are used to represent actual AC electrical quantities in terms of magnitude and phase angle. Voltage and current magnitude and phase angle for all three phases and frequency are the fundamental phasor data collected. Real, reactive and apparent power for each phase and the total are also collected along with power factor. Finally, the zero, positive and negative sequence components of the voltage and current quantities are measured.

One of the best ways to think of phasor data is in comparison to traditional Supervisory Control and Data Acquisition (SCADA) data. Phasor data typically have a scan rate of 30 to 60 samples per second, while SCADA data may have a scan rate of 2 to 5 seconds. Phasor data is very accurately time-tagged so that a state estimator, operator display or planning studies can easily "line up" or resolve what is happening and when. With SCADA information, which is not always time-tagged, some data points are newer than others, but there is no way to tell the difference. Phasor data collection makes use of modern communication network technology whereas SCADA data often uses legacy communications and was never meant to respond to rapidly changing system transient events. One major benefit of phasor data comes from the ability to measure electric power flows at the same instant at hundreds of critical points across a 1,500-mile-wide grid, using precise time signals from global positioning system (GPS) satellites.

For a real life comparison between phasor and SCADA data: With SCADA, "It's as if you're driving a car at 60 miles an hour and you open your eyes every four or five seconds to see where you're going. That's kind of what we're doing now," said Chantal Hendrzak, general manager of applied solutions at the PJM Interconnection. "Where that really bites you is when you have these dynamic stability conditions that have the potential to quickly cascade and spiral out of control undetected." With synchrophasors, "you're blinking your eyes 30 to 60 times a second." That should greatly improve understanding of the grid's condition,47.

The actual collection of the phasor data involves the key components mentioned above: a phasor measurement unit (PMU) and a phasor data collector (PDC). The PMU is installed at the substation or switchyard and makes high-bandwidth, high-frequency, GPS time-stamped, synchronized measurements. The PDC polls all the PMUs 30 to 60 times per second and stores the recorded measurements. The PDC may be at a central location or at the substation if multiple PMUs are present at the substation. The data is communicated to or between PDCs over a communications infrastructure to a central PDC. The communications infrastructure is ideally a secure Wide Area Network with high bandwidth to support a range of applications. The central PDC may in turn deliver the phasor data to a suite of specialized real time and off-line applications and to a regional or national phasor data collection system such as the planned NASPInet.

Although large-scale blackouts are very low probability, multiple contingency events, they carry immense costs and consequences for customers and society in general as well as for power companies48. The barriers and high costs for building new transmission lines and other mitigation strategies have combined with load growth and other factors to increase the probability of major outages. The twin imperatives of mitigating the risks of large blackouts while deriving maximum utilization of installed asset such as transmission lines is driving

[47] Peter Behr, NY Times, "Devices emerge to handle the quirks of adding more renewable energy to the grid", June 8, 2009

[48] Wide Area Protection and Emergency Control"; Daniel Karlsson, Gothia Power AB, Sweden; from panel: "Cascading Failures and Blackouts"; 2005/2006 IEEE PES T&D Conference and Exposition Dallas, Texas –May 21-26, 2006

investment in new technologies. Many leaders and authorities in the utility industry including the FERC, DOE, NERC, NASPI, WECC and the CEC believe that phasor measurement data is becoming essential for the optimal stable operation of the system. Phasor data enables a range of new applications of high value including those for operator situational awareness, and wide area protection and control. For example, one utility[49] is using phasor data to provide improved control of a static–VAR compensation system.

Applications:

Application	Support
Transmission Applications	
Wide Area (Phasor) Measurement	Phasor measurement units are required
Wide Scale Outage Recovery	Phasor measurement units can be an element of this application

Costs:

Depending on the system requirements and the availability of existing equipment such as relays, digital fault recorders (DFRs) or other equipment, it may be possible to upgrade (existing devices) to add phasor measurement at a low cost of $1,500 to $5,000 plus the cost of communications equipment. If new dedicated phasor measurement equipment is required the cost may vary from $15,000 to $30,000 depending on channel capacity and features.

Maturity:

Until recently the pace of adoption of phasor measurement technology has been slower than expected, in part, because of a lack of available applications with compelling economic justifications. Conversely, it has been hard for industry and academia to justify efforts to develop the needed applications when limited research funds are available, few utilities have installed phasor measurement equipment and there is inadequate grid level infrastructure for robust communications and concentration of phasor data. Fortunately the combined efforts of NASPI, NERC, DOE and FERC as well many utilities are addressing these issues. There is now a growing collection of valuable phasor data applications implemented by multiple utilities. To date there are an estimated 200+ PMUs installed in North America with a further estimated 800+ units anticipated over the next few years. A nationwide robust phasor data network referred to as NASPInet is in the process of being defined and planned.

[49] Anthony Johnson, SCE – "Successful Utilization: Phasor Data in Closed Loop Control", March 2008

Protective Relays

Description:

The electrical system routes significant energy from place to place without incident, almost all of the time. On rare occasions, the system encounters a problem. Most often, the problem is a short circuit, or a fault. Faults are typically an event that is associated with sudden high currents and low voltages. The fault establishes an electrical path other than the intended path and will cause damage as energy takes this unintended path.

Protective relays are the devices that continuously monitor the circuits and detect faults and unusual conditions. If a fault is detected, the protective relays trip the circuit breaker and shut down the failed circuit.

Modern digital protective relays. These connect to the voltage and current sensors on the lines. The continuously monitor conditions and compare the real-time data to preset limits and rules.

The protective relay protects life and property. If a power line should contact the earth, a tree, a ladder, or any item that can conduct electricity, a hazard exists to anyone in the vicinity. These relays are designed to detect not only short circuits that release a great deal of energy, but other abnormal conditions. Relays are deployed in overlapping fashion, such that all areas of the electrical system are protected by two or more systems, each with independent sensing circuits and separate wiring. In the future, more relays will connect digitally, using IEC 61850 protocols and sharing information to improve the decision-making process.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Protective relays can be an element of this application
Improved fault location	Protective relays can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Protective relays can be an element of this application
Transmission Applications	
Wide Scale Outage Recovery	Protective relays can be an element of this application

Costs:

Modern protective relays cost a few thousand dollars each. A full protection panel with multiple protection schemes and the necessary communications interfaces may cost $100,000.

Maturity:

Protective relays and fuses have been employed since the early electric system days. The technology has improved significantly. In the early 20th century protective relays based on the induction coil technology of watt meters were in wide use. Those are being replaced with modern digital protective relays as repair parts become unavailable.

Power Quality Monitors

Description:

The AC power supplied and delivered within North America has specific nominal values and a sinusoidal shaped wave form, according to specifications and history. Significant deviations from the expected voltage or wave form can cause consumer equipment to malfunction. The quality of the delivered power is adequate as long as it powers the connected equipment to work as intended; poor power quality results in equipment mis-operation and malfunction.

Power quality monitors compare the supplied power to a given set of limits and trigger data capture in the case of any out of tolerance voltage deviations. The quantities measured may include:

- Phase-to neutral voltages
- Phase-to-phase voltages
    - Voltage Dips, Swells and interruptions
- Phase currents
- Power factor and phase angles
- Voltage harmonics (waveform distortion)
    - Individual harmonic magnitudes
    - Total harmonic distortion
- Voltage flicker
- Frequency deviations, over or under nominal frequency
- Unbalance of voltage or current
- Power and Energy
    - Watts
    - VA
    - VARs
    - Watt-hours
    - VA-hours

Some power quality monitors can plot trends showing the weekly, monthly, or year-long records of the quantities monitored.

Power quality monitors are used as diagnostic instruments. They are applied wherever the electric power is mission-critical to the work being done. That may be a data center or similar facility critically dependent on commercial power. Power quality monitors are useful in diagnosing problems with customer electronic equipment.

Applications:

Application	Support
AMI Applications	
Power Quality/Voltage Monitoring at the Meter	This application uses AMI meter data to supplement more capable power quality monitors
Distribution Automation Applications	
Dynamic System Protection for Two-Way	Power quality monitors could provide input

Power Flows and Distributed Resources	to protection scheme development for distributed resources
Dynamic Volt-VAR management	Power quality monitors could provide input to the Volt-VAR management scheme development
Conservation Voltage Optimization	Power quality monitors could provide input for optimization
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Power quality monitors may be an element of this application
Asset condition monitoring	Power quality monitors may be an element of this application
Enhanced System Modeling and Planning	Power quality monitors may be an element of this application
Distributed Resource Applications	
Coordinated Management of Distributed Resources	Power quality monitors may be an element of this application
Electric Vehicles : Optimized Charging	Power quality monitors may be an element of this application
Dispatch of Electric Vehicle Storage	Power quality monitors may be an element of this application

Costs:

Power quality monitors range in cost from hundreds to tens of thousands of dollars, depending on the quality of the data gathering.

Maturity:

Power quality monitors are widely available by a number of providers, and are a mature product.

Transformer Monitoring and Dynamic Rating

Description:

Substation power transformers are among the most expensive, critical and difficult to replace assets in the transmission and distribution networks. Therefore utilities are motivated to utilize the transformers for as many years as possible but without incurring too much risk of unplanned outages or expensive failures. This is becoming more of a challenge for many utilities as the average age of these assets has grown to 42 years in

North America. At the same time, operational practices have changed to allow higher continuous and peak loading on these aging transformers. Asset maintenance departments attempt to mitigate the risk of unplanned outages and failures but these efforts can be expensive especially if maintenance is conducted without comprehensive condition information.

On-line transformer monitoring sensors are available that can detect a wide range of failure types. Note also that some sensor types, such as dissolved gas analysis, are able to detect a number of different failure modes. The primary goals of on-line monitoring are to provide:

- an early warning of a pending failure
- an indication of equipment condition

The ability to alert the maintenance personnel when equipment needs maintaining can enable to utility to increase reliability at the same time as reduce maintenance costs. Rather than perform inspections and other maintenance tasks on a strictly schedule basis, these tasks can be performed far less frequently or only when alerted.

Device	Description
Dissolved Gas Analysis (DGA)	Combustible gases are generated due to heating in the insulating oil and insulating paper of a power transformer. Excessive heating is usually indicative of a fault. Different gases or combinations of gases are generated at varying rates by different temperatures and fault types. Examples of scenarios that produce gases include overheated paper insulation, overheated oil, overheated metal, partial discharge and arcing. Analysis of individual gas levels and ratios of the different gases can yield information on the nature of the fault. Lab tests are a reliable method for most analysis but have limitations due to the delay in getting results, determining moisture levels and cost. For example the rate of change of gas levels provided by sensors is an important parameter that may indicate that a fault is developing. Sensors range from simple single gas units to sophisticated monitoring systems that monitor seven gases, moisture and other parameters such as temperature.
Moisture Sensor	Excessive moisture in the oil can lead to reduced insulating capability for oil and accelerated aging of the paper insulation. A moisture-in-oil sensor typically measures the relative humidity and temperature of the oil.
Top Oil Temperature	A general indication of the temperature of the tank of the transformer. Can be use in conjunction with an algorithm to estimate the winding hot spot temperature. Sensors are typically designed as probes that reach into a thermal well from the outside of the tank.
Winding Hot Spot Temperature	An important indication of the current impact of the load and other factors on the winding of the transformer. The hottest spot of the windings is the location of the fastest aging of the paper insulation so monitoring and responding to this parameter is key to managing overall transformer life.

	Winding hot spot temperature may be monitored directly using sensors such as fiber probes or indirectly estimated from other measurements such as top oil temperature.
Load Tap Changer	Transformer Load Tap Changers (LTCs) may require regular inspection and maintenance due to frequent mechanical operations. Failures of LTCs can result in significant damage to the transformer. An LTC monitor analyzes and reports key parameters such as the tap position, drive motor current, load current, number of tap changes per day, contact wear and overall mechanical wear. Vibration signature analysis is also becoming an effective tool although these devices are off line at this time.
Bushing Sensors	Bushing failures, while rare for most utilities, can result in sudden catastrophic failure of the transformer. This device performs an analysis on the bushing leakage current of both the HV and LV bushings. The system calculates power factor changes and capacitance of the bushings. A benchmark value is set, and once a change is detected, the system will identify the bushing that is experiencing a problem.
Partial Discharge Monitors	In power transformers, partial discharge (PD) is an exchange of energy (fault) caused by a partial breakdown of the insulating material such a paper or oil. PD is exhibited with low energy faults while arcing is exhibited with high energy faults. PD may occur internally or externally (eg visible burn tracks on the surface of insulation) to the insulating system. Detection methods typically use acoustical (sound) or electrical methods. Acoustical PD sensors must be applied to a specific piece of equipment and can aid in identifying the location of the fault. Electrical PD sensors provide broad coverage at a substation but offer limited assistance in locating the fault.
Cooling System Control and Monitoring	Transformer cooling systems normally involve the pumping of the oil from the top of the tank, through fan cooled radiators and returning to the bottom of the tank. Ideally the cooling system is controlled in stages according to the cooling needs of the transformer. Cooling can be controlled in response to top oil temperature, winding hot spot temperature or load current. Cooling system efficiency can be monitored by comparing actual temperature changes to estimated (calculated) values.
Integrated Transformer Monitoring and Diagnostics Systems	Integrated systems collect data from the on-line sensors on the transformer, store the data, monitor for trends, and utilize analysis models to derive additional information such as rate of aging and dynamic loading capability. In addition these systems control the cooling equipment and communicate the information to local and remote users and applications.

The decision on what types of sensors should be used on each transformer needs to include a risk assessment. Appropriate monitoring (if used) may range from a single sensor type to an integrated system that incorporates many types of sensors as well as diagnostics models. Risk is determined by combining the probability of a type of failure occurring and the impact or consequence of that failure. For example, this method may result in a lower investment such as a single sensor for a small transformer at a distribution substation. Alternatively, the risk presented by an aging, large Generation Step-Up Unit (GSU) near a power plant may justify a comprehensive integrated monitoring and diagnostics system with analysis models.

The addition of analysis models can greatly enhance the on-line condition assessment of the transformer. Example analysis models are:

- Estimated winding hottest spot
- Dynamic capability rating
- Insulation rate of aging
- Cumulative age
- Cooling control
- Cooling system efficiency
- Moisture bubbling threshold
- Data correlations between parameters

Another driver to determine the type and number of sensors warranted for a transformer is dynamic rating capability. This refers to the real time load capability of the transformer on a current and a "look ahead" basis. Static ratings are usually calculated on a conservative basis using name plate or manufacturers figures. In reality, a transformer is often capable of carrying a higher (sometimes much higher) load for a limited period of time provided that the unit is comprehensively monitored. The ability to dynamically load the unit can be a very valuable tool for a system operator faced with decisions to shed load or dispatch expensive power.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Transformer monitoring can be an element of this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Transformer monitoring can be an element of this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Transformer monitoring can be an element of this application
Asset condition monitoring	Transformer monitoring can be an element of this application
Enhanced System Modeling and Planning	Transformer monitoring can be an element

	of this application
Transmission Applications	
Wide Area (Phasor) Measurement	Transformer monitoring can be an element of this application
Wide Scale Outage Recovery	Transformer monitoring can be an element of this application

Costs:

On-line monitoring for lower risk installations may warrant a single sensor costing $5,000 to 8,000 plus communications and installation. Comprehensive monitoring and diagnostics systems that integrate multiple sensor types, analysis models, fault measurement, control capability and communications technologies may cost in the range of $50,000 to $100,000 depending on the features required.

Maturity:

On-line monitoring of transformers has been successfully implemented since the mid 1980's and many of the sensor technologies are now in their 3rd or 4th generation. Nevertheless the environment that the sensors must operate in is very harsh and, in the earlier generations, resulted in some unreliable or shorter (than expected) life installations. Therefore it is important to thoroughly field test equipment and obtain references from other utilities before making purchase decisions.

Telecommunications Network Technologies

Premises Networks

Description:

The consumer's options for using or integrating smart grid enabling home area network technology are vast. Many markets, consistent with NIAP studies on broadband access and the Pew studies on broadband access, have been shown to have broadband internet access. Uptake by consumers of home area network technology is generally correlated with their access to broadband and broadband delivered services. The majority of the internet connected market is dominated by IEEE 802.2 bearing media of one form or another, specifically IEEE 802.11 Wi-Fi (a wireless technology with ~100Mb bandwidth) and Ethernet (a wired networking technology with Gb bandwidth).

Meter vendors, meter communications vendors, 3rd party demand response providers, and utilities have focused on adoption of various home area network technologies based on well defined utility requirements including security, manageability, application support, unit cost, unit power consumption, and similarity to existing home automation technology (which currently differs significantly from broadband internet enabled home area network technology). Technologies include: ZigBee, HomePlug, Z-Wave, Bluetooth, INSTEON, LONWorks, UPB, X-10, MoCA, and many more specialty technologies. Notably, HomePlug, Bluetooth, MoCA, and ZigBee are all IP compatible media. HomePlug is additionally an 802.2 compatible media. Recent developments in lower cost, lower power IEEE 802.11n (Wi-Fi) implementations are causing utilities to re-evaluate IEEE 802.11n for meter interconnection. Expansion of utility interest is noted by the recent creation of alliance subgroups in Bluetooth, Z-Wave, and the Wi-Fi alliance.

Some technologies, such as ZigBee, have constructed application profile specifications to support rapid market development of appliances and services that enable smart grid applications. Other network technologies have focused on enhancing their ability to support future applications while meeting utility performance requirements as well.

Utilities are seeking to build a limited number of home area network application specifications and standards, and offer them as an interface from meter or home attached gateways. The role of the AMI meter in the HAN is crucial as it represents the best place to get high resolution consumption data for the premises. Part of the coming Smart Energy applications include real time update of in-home displays, whether stand alone, appliance integrated, or customer application integrated.

Currently several groups are in development of application specifications for home area network technology and utility application integration. Organizations include UCA/OpenSG/OpenHAN, UCA/OpenSG/OpenADE, UCA/CIMug, PIER/OpenADR, IEC TC-57, Association of Home Appliance Manufacturers (AHAM), and many more. Requirements from these bodies are being rapidly incorporated in the ZigBee Smart Energy Profile (SEP) development work. The US home energy application market differs from market action observed in Europe; the European OPENmeter project proposes use of DLMS/COSEM for meter to home applications.

Applications:

Application	Support
AMI Applications	
Customer Prepayment Utilizing AMI	Premises network required
Customer Oriented Applications	
In-Premises Device for Energy Usage Data	Premises network required
Customer Web Portal for Energy and Cost Data	Premises network may enhance this application
Outage Notification to Customer	

Demand Response Applications	
Price Information to In-Premises Devices	Premises network required
Direct Load Control	Premises network required
System Frequency Signal to Customer Load Control Devices	Premises network required
System Renewables Output to Customers	Premises network may enhance this application
Distributed Resource Applications	
Customer Distributed Resource Interconnection	Premises network may enhance this application
Coordinated Management of Distributed Resources	Premises network required
Electric Vehicles : Optimized Charging	Premises network required
Dispatch of Electric Vehicle Storage	Premises network required

Costs:

Network device costs in volume vary widely from approximately $1 to $75 per communication node depending on the technology selected, technology complexity, integration costs, and other market considerations. What is expensive today may be very affordable tomorrow. Additionally, low cost technologies with basic functionality may be obsolete within 5 years, though this is not always the case. A good example being X-10's over 30 year life span in the market.

Maturity:

The network technologies serving the broadband Internet market are very mature. Technologies serving traditional home automation markets are higher priced and have relatively low installed bases and are therefore often less mature than mass-market technologies. Technologies being developed by utilities and smart grid industry partners for rapid market uptake represent a relatively immature base of products. It is expected that as utilities select technologies aligned with the needs of the typical internet connected home, the maturity of such products will increase rapidly.

AMI Network

Description:

The AMI Network is the 'nervous system' of the entire AMI deployment and as such plays a key role in all applications. The mix of technologies to reach every customer must be balanced by a rigorous business case to support the deployment of this infrastructure. The choice of technology is tied to customer density, with few deployments able to be made with a single AMI Network technology. Most vendors use a mix of proprietary and standards-based technologies for the AMI Meter Network.

Wireless

Wireless systems can operate at many different frequencies. Free, unlicensed bands are available at 433 megahertz (MHz), 915MHz, and 2.4 gigahertz (GHz), which represent the center frequencies of those bands. Other, licensed bands exist at several other frequencies. As a general rule, lower frequencies propagate better, meaning that the signals travel further through the air with less attenuation, or signal loss. Lower frequencies also reflect off surfaces and can get around and through obstacles better. As a general rule, lower frequencies are preferred. The need for good signal propagation is more important in a many-to-one (star) architecture than in a pure many-to-many (mesh) architecture for purposes of communications reliability.

Bandwidth is also an important factor. In the 915MHz range, the FCC allows the use of 902 to 928MHz, a 26MHz wide band, on an unlicensed basis. This bandwidth translates to how much data can be passed around the network in a given time. A key metric is the total bandwidth (the number of simultaneous channels multiplied by the bit-rate per channel). In addition, the raw speed (in bits-per-second) and throughput of the network are of interest.

Unlicensed system advantages include the lack of licensing and country-wide availability. Disadvantages include:

- A multitude of interfering devices such as wireless phones, baby monitors, security camera systems and the like
- Difficult or missing dispute arbitration from the FCC for interfering transmitters

The use of a licensed frequency, in contrast to the unlicensed spectrum, guarantees availability of the communication channel to the licensee, with clear arbitration rules set forth and enforced by the FCC. The major disadvantage is that a specific operating frequency may not be available in all desired service territories.

Wi-Fi

IEEE 802.11 (Wi-Fi) is a local area network technology that is used to provide short range (100-300 feet outdoors) connectivity in the 2.4 GHz (802.11b, g) and 5.8 GHz (802.11a) bands. The data rate varies from 11 Mbps (b) to 54Mbps (a, g). Because of the power and signal limitations, this is not a practical medium for sparsely populated areas, but can work in more urban settings via a series of hotspots that can then also be used by the local utility for other offerings to their customers.

WiMAX

IEEE 802.16 (WiMAX) is a wireless metropolitan area network (MAN) technology that is intended to connect IEEE 802.11 hotspots to the Internet and provide a wireless extension to cable and DSL for “last mile” broadband access. WiMAX uses frequencies in the 2-11GHz and 10-66GHz ranges; the former is restricted to line-of-sight communications but the latter is not. The intended deployment of WiMAX is in networks with a wide coverage pattern similar to cellular telephony, rather in multiply linked hotspots as Wi-Fi is now used. The WiMax Forum expects that IEEE 802.16 could deliver up to 20Mbps per channel (70Mbps total) in typical cells with radii of 3 to 10 kilometers without direct line-of-sight to a base station. Some predict a potential maximum range of 50km in line-of-sight mode.

Wired-Power Line Communication

Power Line Communication (PLC), originally called Power Line Carrier, is the transfer of data over existing electric power lines. Narrowband PLC systems involve relatively high-speed (but not as high as broadband over power line, or BPL) communication from the utility to end customers. The frequencies involved in this type of communication do not propagate through distribution transformers and require special equipment or advanced signal processing techniques to bridge around them. Because of this requirement, use of Narrowband PLC for AMI has only been successful in places like Europe where many (>50) customers generally share a single distribution transformer. As a result, the international standards for customer access via narrowband PLC are mostly European-based. The most popular narrowband PLC systems in North America are used within the customer site, and are a competitive option for customer in-premises networks.

Low frequency PLC refers to PLC technology that provides a lower bandwidth and lower data rate with a longer propagation capability over the electric distribution infrastructure. The low frequency signals do not require special equipment to bypass power transformers, which act as low-pass filters for some communications signals. An advantage of low-frequency PLC is that the signal can travel many miles before requiring boosting equipment. This technology is most often used by utilities to perform switching or control operations such as relay tripping and water heater management, as well as by some vendors to perform meter reading applications. While a robust technology, the low bandwidth tends to limit the types of applications that are often considered in smart grid deployments.

Broadband over Power Line (BPL) refers to PLC technology that provides “last mile” digital broadband capabilities over electric distribution infrastructure. Like other power line technologies, this “last mile” capability is technically constrained by the ability to propagate the signal through the power transformers in the distribution system (those act as low-pass filters and attenuate the high-frequency PLC signals) and the ability for the signal to travel longer distances, which is a function of both the natural attenuation of the power wires and the signal power limits imposed by the FCC.

In addition to utility applications, BPL supports commercial applications such as high-speed internet access, video on demand and streaming audio.

“Access” BPL is the term for technology that carries broadband traffic over medium and low-voltage power lines. This is accomplished by overlaying digital communications equipment at certain points along the electric power distribution network. Three components of the electric power distribution network are directly involved. The first is the medium voltage (4 to 40kV) line over which an electric utility brings power from a substation to a residential neighborhood. The second component is equipment used to bypass the low-voltage transformers, that is, those that step the line voltage down to the residential 240V service level. The third component is the low voltage distribution network (in some cases a single line) from the pole-top step-down transformer to residential service panel and on into the premises.

“In-house” BPL is a home networking technology that uses the transmission standards developed by consumer groups such as the HomePlug Alliance. Products for in-home networking use the electric outlets and wiring within a premises as the communications path.

Applications:

Application	Support
AMI Applications	
Core AMI Functionality	AMI network is required for this application
Remote Connect/Disconnect	AMI network is required for this application
Outage Management Support	AMI network is required for this application
Power Quality/Voltage Monitoring at the Meter	AMI network is required for this application
Customer Prepayment Utilizing AMI	AMI network enhances this application
Customer Oriented Applications	
In-Premises Device for Energy Usage Data	AMI network enhances this application
Customer Web Portal for Energy and Cost Data	AMI network is required for this application
Outage Notification to Customer	AMI network enhances this application
Demand Response Applications	
Price Information to In-Premises Devices	AMI network enhances this application
Direct Load Control	AMI network enhances this application
System Frequency Signal to Customer Load Control Devices	AMI network enhances this application
System Renewables Output to Customers	AMI network enhances this application

Distribution Automation Applications	
Automatic circuit reconfiguration	AMI networks can support this application
Improved fault location	AMI networks can support this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	AMI networks can support this application
Dynamic Volt-VAR management	AMI networks can support this application
Conservation Voltage Optimization	AMI networks can support this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	AMI networks can support this application
Asset condition monitoring	AMI networks can support this application
Enhanced System Modeling and Planning	AMI networks can support this application
Distributed Resource Applications	
Customer Distributed Resource Interconnection	AMI network enhances this application
Coordinated Management of Distributed Resources	AMI network enhances this application
Electric Vehicles : Optimized Charging	AMI network enhances this application
Dispatch of Electric Vehicle Storage	AMI network enhances this application

Costs:

The AMI Network cost is typically bundled with the cost of the AMI Meter and the cost of the AMI Management System. Utilities perform an analysis which considers the geographical nature of their service territory, network performance for the smart grid applications to be supported and the number of network devices (collectors, concentrators, repeaters) required by various network technologies.

Utilities often compare the total cost of their AMI system (AMI Meter, AMI Network, AMI Management System) installation averaged across the total number of meters installed. Average installed system costs for large utilities typically range from $250 to $350 per meter when averaged across very large numbers of meters.

Maturity:

The wired and wireless technologies for AMI Networks are mature technologies, but their application for two-way communications in this domain is relatively new.

Low data rate (PLC) wired technologies are mature, generally suffer from the electric distribution system's design of few customers per transformer (hence, many transformers), where the transformer often serves as a "filter" to prohibit communications. Early mitigating technologies required additional equipment to bypass the transformers and provide reliable connections. Newer technologies have been developed that "tunnel" through the transformer and require less equipment.

High data rate (BPL) wired technologies are relatively new for the power industry. The bandwidth needs for interval data metering even in a dense network are much lower than those for the same number of extremely active, media-consuming internet customers.

Wide Area Network

Description:

Utility Field Networks and Wide Area Networks - Introduction

A network is required in order to communicate with and gather information from the devices that will be installed by the utility in substations, on poles, and customers' premises.

In some cases utilities are choosing to use existing point to point communications, radio networks and leased lines to go from one location to another. Many of these networks have been in place for 20 years or longer and were designed for specific purposes. Some were installed during the late 1990s when fiber optics was considered a good investment by the industry. In most cases, the existing networks were not designed to support the needs of the smart grid.

Issues of age, design and coverage have lead to utilities talking about a Utility Field Network. This network would provide universal coverage to all devices, with latency that is low enough to support control actions for specific devices and enough bandwidth to support bulk data gathering from others.

The field network would cover all locations that the utility delivers electricity to and the utility's transmission and distribution system. The network could be a single technology or multiple technologies, depending on customer and device density, data rates, latency requirements and existing infrastructure. It will likely evolve over time as new devices and communications technologies become available.

In Canada the Canadian Government set aside frequency space for utility field networks country wide. The Federal Communications Commission (FCC) has made several recommendations in the National Broadband Plan related to utility networks, including:

- States should reduce impediments and financial disincentives to using commercial service providers for Smart Grid communications
- The North American Electric Reliability Corporation (NERC) should clarify its Critical Infrastructure Protection (CI P) security requirements
- Congress should consider amending the Communications Act to enable utilities to use the proposed public safety 700MHz wireless broadband network

- The National Telecommunications and Information Administration (NTIA) and the FCC should continue their joint efforts to identify new uses for federal spectrum and should consider the requirements of the Smart Grid
- The U.S. Department of Energy (DOE) in collaboration with the FCC , should study the communications requirements of electric utilities to inform Federal Smart Grid policy

The field network is a key portion of a smart grid, providing a path for data and commands to flow between devices in the field and operators in the control center. In addition some utilities are looking at putting their field work force on the same network to manage costs and provide more information to the field teams.

Wide Area Network

The wide area network is the portion of the network that runs from the central location to key locations in the field where concentrators are located. The concentrators are designed to gather information from one or more types of devices and send commands back to those devices. The wide area network typically is made up of microwave, fiber optic and leased lines with a capacity to move large amounts of data from one location to another.

Utility Field Network

The field network is the portion of the network that runs from the concentrators to the end devices. This portion of the network is typically cellular, radios, power-line or fixed line depending on the devices and latency required.

One of the terms often heard is a "mesh network" the mesh network is typically a Utility Field Network where one device talks to another and that one to another one until one device can reach the concentrator. This reduces the number of concentrators required and provides the ability for the network to adjust as needed to environmental conditions, finding new paths for information to flow to and from the concentrator, if a concentrator is out of service, a good mesh network will find the next concentrator and re-route the data to that one automatically.

Applications:

Application	Support
AMI Applications	
Core AMI Functionality	Wide Area Network may be required depending on AMI network technology
Remote Connect/Disconnect	Wide Area Network may be required depending on AMI network technology

Outage Management Support	Wide Area Network may be required depending on AMI network technology
Power Quality/Voltage Monitoring at the Meter	Wide Area Network may be required depending on AMI network technology
Customer Prepayment Utilizing AMI	Wide Area Network may be required depending on AMI network technology
Customer Oriented Applications	
In-Premises Device for Energy Usage Data	Wide Area Network may be required depending on AMI network technology
Customer Web Portal for Energy and Cost Data	Wide Area Network may be required depending on AMI network technology
Outage Notification to Customer	Wide Area Network may be required
Demand Response Applications	
Price Information to In-Premises Devices	Wide Area Network may be required depending on AMI network technology
Direct Load Control	Wide Area Network may be required depending on AMI network technology
System Renewables Output to Customers	Wide Area Network may be required depending on AMI network technology
Distribution Automation Applications	
Automatic circuit reconfiguration	Wide Area Network may be required
Improved fault location	Wide Area Network may be required
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Wide Area Network may be required
Dynamic Volt-VAR management	Wide Area Network may be required
Conservation Voltage Optimization	Wide Area Network may be required
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Wide Area Network may be required
Asset condition monitoring	Wide Area Network may be required
Enhanced System Modeling and Planning	Wide Area Network may be required
Distributed Resource Applications	
Customer Distributed Resource Interconnection	Wide Area Network may be required depending on AMI network technology
Coordinated Management of Distributed Resources	Wide Area Network may be required
Electric Vehicles : Optimized Charging	Wide Area Network may be required depending on AMI network technology
Dispatch of Electric Vehicle Storage	Wide Area Network may be required

	depending on AMI network technology
Transmission Applications	
Wide Area (Phasor) Measurement	Wide Area Network may be required
Wide Scale Outage Recovery	Wide Area Network may be required
Enhanced physical security	Wide Area Network may be required

Costs:

Costs for wide area networks vary greatly based on the technology and the size of the network. Utilities can expect costs in the hundreds of thousands of dollars or greater.

Maturity:

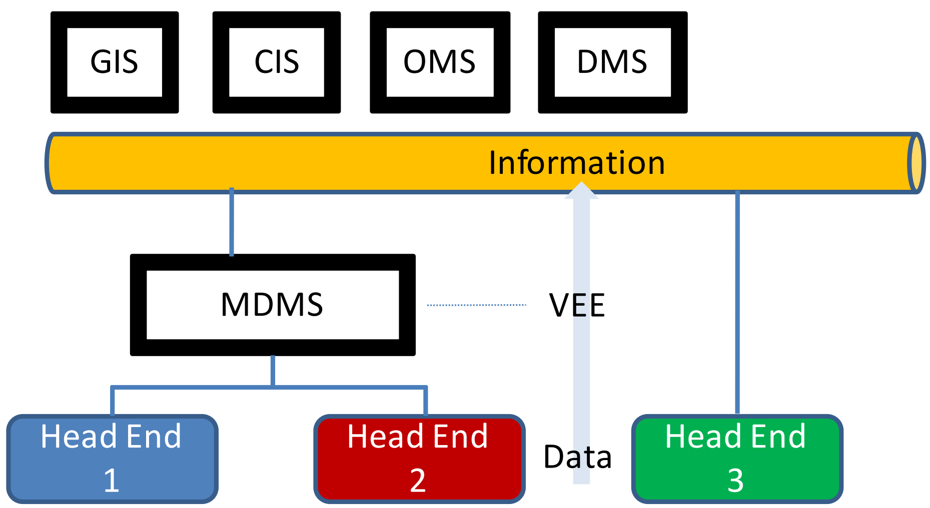
Wide area networks are based on mature telecommunications industry technologies and while expensive to plan and install have low technical risk.

Enterprise Systems Technologies

The simple graphic below depicts a hypothetical utility information system

- Three 'head end' systems for various communications networks
- A meter data management system (MDMS)
- Four utility systems
  - Geographic information system (GIS)
  - Customer information system (CIS)
  - Outage management system (OMS)
  - Distribution management system (DMS)

This graphic is useful to understand the relationship between these systems and the information being exchanged.



AMI Management System

Description:

The AMI Management System (AMI-MS) is often given different names by vendors such as "head end" system, or in standards such as "metering system" as defined in the IEC 61968-9 standard.

The AMI-MS is both software on a server used to manage the AMI Network and the hardware necessary to communicate with all devices in the field. The AMI-MS is used to manage the communications network (siting, commissioning, pathway management, device registration/deregistration, security), the utility to meter commands (switching, updates, configuration, rates, price signals, security) in real-time or on a schedule, the data flow from the customer to the utility (revenue data, command responses, security) on configurable schedules, and any other function that is needed to manage the meters and related equipment such as real-time, on-demand readings and “pings”. Ideally, the AMI-MS would either be capable of graphically indicating system and device status or be tied to a GIS that allows the same.

The AMI-MS is needed for all AMI system functions, from local configuration management via a hand-held tool to remote switching commands and verification signals. Included in these functions may be some intelligence related to data aggregation for outage management, command balancing for service connects and disconnects, and bandwidth management for large data uploads (interval billing data) and downloads (firmware updates, configuration changes). The AMI-MS is also leveraged by other utility systems to interact with non-revenue meter devices (distribution equipment such as voltage monitors, transformer and feeder meters, capacitor banks, etc.) for monitoring and control. Some vendors have built meter data management capability into their AMI-MS to the extent that a separate application is unnecessary. This is particularly true for public power (municipals and co-op’s) applications.

Applications:

Application	Support
AMI Applications	
Core AMI Functionality	AMI management system required
Remote Connect/Disconnect	AMI management system required
Outage Management Support	AMI management system required
Power Quality/Voltage Monitoring at the Meter	AMI management system required
Customer Prepayment Utilizing AMI	AMI management system required
Customer Oriented Applications	
In-Premises Device for Energy Usage Data	AMI management system required if using AMI meters as in-premises gateway
Customer Web Portal for Energy and Cost Data	AMI management system required
Demand Response Applications	
Price Information to In-Premises Devices	AMI management system required if using AMI meters as in-premises gateway
Direct Load Control	AMI management system required if using AMI meters as in-premises gateway
System Renewables Output to Customers	AMI management system required if using AMI meters as in-premises gateway

Distribution Automation Applications	
Automatic circuit reconfiguration	AMI management system required if using AMI network
Improved fault location	AMI management system required if using AMI network
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	AMI management system required if using AMI network
Dynamic Volt-VAR management	AMI management system required if using AMI network
Conservation Voltage Optimization	AMI management system required if using AMI network
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	AMI management system required if using AMI network
Asset condition monitoring	AMI management system required if using AMI network
Enhanced System Modeling and Planning	AMI management system required if using AMI network
Distributed Resource Applications	
Customer Distributed Resource Interconnection	AMI management system required if using AMI network
Coordinated Management of Distributed Resources	AMI management system required if using AMI network
Electric Vehicles : Optimized Charging	AMI management system required if using AMI network
Dispatch of Electric Vehicle Storage	AMI management system required if using AMI network

Costs:

The AMI-MS is not “sold separately” due to the reliance on each particular vendor’s equipment hardware, software and firmware; as such, the cost is part of the entire AMI system deployment.

Maturity:

Most vendors have a grasp on managing large numbers of devices with their software and hardware systems though the vast portion of that experience is in one-way systems. Considerable R&D has been and will continue to be expended on these systems since they are the critical link to the potentially millions of meters and the utility enterprise applications and most are considered both robust and mature at this time.

Meter Data Management System

Description:

Before delving into a description of common meter data management system (MDMS) functions, it is worthwhile to discuss what MDMS are not. This can help to dispel misconceptions as to the need for an MDMS and the benefits they provide. Separate Meter Data Management Systems are not strictly required to enable particular utility applications. Rather, they are part of a more organized, manageable, and maintainable back-office system architecture.

- MDM systems are not strictly required for interfacing with billing systems. AMI Management System software can generally be directly interfaced to billing systems.
- MDM systems are not often used for real-time AMI Meter interactions.
- An MDM system is not required in order to have advanced rates, like TOU or dynamic pricing.
- MDM systems are not required for demand-response programs – both event-announcement and verification can be handled outside an MDM.
- While the warehoused meter data in an MDMS is valuable to utility applications, the MDMS itself is not necessarily involved with the communications to field equipment.

Some vendors describe a meter data unification system (MDUS) which in their definition plays a more critical command and control link within their utility enterprise system. This is not a requirement, but rather a sign of their particular enterprise application architecture.

MDMS are focused on collecting metering data from one or many diverse sources, harmonizing the data, and serving as the long-term repository and historian (data warehousing). The collected meter data is often married with other information, like customer or geographical data, and then provided to other applications in a meaningful manner.

MDMS outputs may minimally be a set of validated, edited or estimated interval energy values with a serial number, for example, where the MDMS has performed the validating/editing/estimating (VEE) function on the collected data. The CIS may then match that information with the customer record on a monthly basis to produce a bill. The MDMS does not need to have knowledge of the entire customer record, only an agreed-upon key value to provide the data for that particular query. For most deployments, the MDMS may also serve as the system of record for this critical data.

Other MDMS consolidation and streamlining functions are:

- MDMS-based data integration with multiple utility information systems
- Integration of meter-related data from multiple sources into a single repository

- Advanced analytics for processing meter-related and operational data in the MDMS repository
- Revenue system of record
- An expected MDMS benefit is cost reductions for the following utility activities:
- Billing research in response to customer inquiries
- Reduction in number of service orders for special reads (when combined with two-way communications to every meter)
- Remote disconnections and reconnections (when combined with two-way communications to every meter)
- Electrical theft detection and revenue recovery
- Reduction in number of trouble calls due to prior utility knowledge of service problems
- Payment collections for service restoration
- Reduction in number of distribution and transformer outages
- Reduction in customer interruptions, minutes of lost service
- Outage information feedback to customers
- Automated outage verification (through AMI infrastructure)

MDMS data is also expected to improve other utility operations since this customer load-level data will complement the existing system component-level data for many planning and operations analyses. These analyses include:

- Forecasting: Predict system load and usage to avoid imbalances and to reduce off-network purchases.
- System planning: Pinpoint over- or under-utilized infrastructure.
- Energy delivery: Protection and asset management.
- Maintenance: Speed service restoration after outages; reduce costs associated with service disconnects / reconnects; reduce costs due to over/under-sized assets.
- Regulatory compliance: Audit records and security (EPACT 2005; Sarbanes-Oxley Act); PUC-mandated outage records.

Applications:

Application	Support
AMI Applications	
Core AMI Functionality	MDMS can enhance this application
Remote Connect/Disconnect	MDMS can enhance this application
Outage Management Support	MDMS can enhance this application
Power Quality/Voltage Monitoring at the Meter	MDMS can enhance this application
Customer Prepayment Utilizing AMI	MDMS can enhance this application

Customer Oriented Applications	
In-Premises Device for Energy Usage Data	MDMS can enhance this application
Customer Web Portal for Energy and Cost Data	MDMS can enhance this application
Outage Notification to Customer	MDMS can enhance this application
Demand Response Applications	
Price Information to In-Premises Devices	MDMS can enhance this application
Direct Load Control	MDMS can enhance this application
Distribution Automation Applications	
Automatic circuit reconfiguration	MDMS can enhance this application
Improved fault location	MDMS can enhance this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	MDMS can enhance this application
Dynamic Volt-VAR management	MDMS can enhance this application
Conservation Voltage Optimization	MDMS can enhance this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	MDMS can enhance this application
Asset Condition Monitoring	MDMS can enhance this application
Enhanced System Modeling and Planning	MDMS can enhance this application
Distributed Resource Applications	
Customer Distributed Resource Interconnection	MDMS can enhance this application
Coordinated Management of Distributed Resources	MDMS can enhance this application
Electric Vehicles : Optimized Charging	MDMS can enhance this application
Dispatch of Electric Vehicle Storage	MDMS can enhance this application

Costs:

There are no hard costs for MDM systems due to the following variables: number of endpoints read, frequency of readings, number of servers, integration needed to other systems, training needed for utility personnel, ongoing maintenance and operation contract, etc. A rough estimate is five to ten dollars per meter for the AMI deployment (example 1M meters would be 5-10M dollars).

Maturity:

There are varying levels of maturity for the leading systems in the marketplace. Very large scale (2M+ meter) AMI deployments are still underway which will operationally prove the scaling ability of all known systems. Computing power continually increases while price decreases, and all vendors have robust customer engagement and R&D programs to best match the needs of the utilities.

Asset Management/Monitoring System

Description:

Asset management/monitoring systems allow utilities to improve system reliability and reduce cost through improved operations and maintenance of its high value and high cost assets such as power transformers and circuit breakers. Factors driving the increased need for these applications include the growing numbers of assets compared to limited personnel as well as the need to manage risks associated with aging assets. For the electric utility, asset management/monitoring are focused on two primary goals:

- Optimize the Life of Assets by Monitoring Key Health Indicators - Utilities are concerned about identifying conditions leading to catastrophic failures in high-value assets. Asset management solutions typically provide real-time, remote monitoring that can help identify abnormal operating conditions or early failure indications that enable a timely, appropriate response before a situation becomes critical.
- Lower Maintenance Costs and Improve Productivity - Unlike periodic manual testing, real-time asset monitoring provides timely notification with trended contextual data instead of a generic trouble alarm, allowing appropriate event response while lowering the risk of component failure. This increases system reliability and equipment availability and prolongs the life of high-value assets.

Asset management/monitoring systems can be broken down into three components:

- Head End/Master – The head end/master component collects, stores, analyzes, and reports information from field deployed devices and sensors. Some systems may distribute portions of this component at the enterprise and substation levels while others locate these systems entirely at the enterprise level. In either case, data is typically presented via Graphical User Interface (GUI) in two formats:
- Current State – Current state is a snapshot of the asset at an instant in time.
- Trending – Historical view of the values over time. This presentation can be especially useful in identifying problems in time to schedule outages on the asset in question before becoming service affecting.

These systems can also be interfaced with the utility's work management system for automated trouble ticket generation.

- Field devices/Sensors – Many of the Intelligent Electronic Devices (IED) being purchased by utilities provide useful asset management/monitoring information at little or no additional cost. These devices can augment more purpose built sensors such as gas in oil analyzers and acoustic monitors on power transformers and circuit breaker monitors.

- Communications – Reliable and robust communications between the field devices and sensors and the head end/master components is critical to the overall system effectiveness. While serial based communications have been used in the past, the current trend is to utilize IP based services for this function.

Applications:

Application	Support
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Asset management system may enhance this application
Asset condition monitoring	Asset management system is required
Enhanced System Modeling and Planning	Asset management system may enhance this application
Transmission Applications	
Wide Scale Outage Recovery	Asset management system may enhance this application

Costs:

Costs for asset management systems are estimated at $50 - $250 thousand dollars.

Maturity:

Developing technology. Utilities are gaining more experience with these systems as more data from devices become available.

Distributed Resource Management System

Description:

A Distributed Energy Resource Management System (DERMS) consists of the following items:

- Demand Response Program Management

- Demand Response Resource Management
- Demand Resource Event Management
- Demand Resource Measurement and Verification

Demand Response Program Management is responsible for managing Demand Resource Programs. This function handles customer enrollment in these programs. Customers provide Demand Response resources and receive incentives according to program tariffs.

Demand Response Resource Management is responsible for determining a set of Demand Response resources, their operational parameters (size, time of availability, location, etc.)

Demand Resource Event Management handles the execution of a Demand Response event including transmission of a Demand Response event messages to customer and customer DR devices.

Demand Resource Measurement and Verification deals with verifying the actual Demand Response resource supplied compared to the project Demand Response resource expected. This requires calculating the Demand Response baseline, and the measurement and verification of actual Demand Response Resource supplied.

Applications:

Application	Support
Demand Response Applications	
Price Information to In-Premises Devices	Distributed resource/demand response system required
Direct Load Control	Distributed resource/demand response system is likely required
Distributed Resource Applications	
Coordinated Management of Distributed Resources	Distributed resource/demand response system required
Electric Vehicles : Optimized Charging	Distributed resource/demand response system required
Dispatch of Electric Vehicle Storage	Distributed resource/demand response system required

Costs:

The Demand Response Management System installation can vary widely depending on the number of resources and communications infrastructure needed. Basic functionality may be built on top of a Smart Metering system and will run $1 to $5 per customer premises.

Maturity:

Demand Response Management System within the power system environment can be considered an emerging technology. There is a significant increase in utility activities to support Demand Response Management Systems along with supporting standards activities. This will lead to significant, rapid product development/innovation. Integration with Smart Metering is underway.

Distribution Management System

Description:

Each device type – transformers, meters, switch gear, etc – has its own software that is provide by the vendor to support data collection and analysis. This is wonderful for engineering and planning, but poses problems when an operator needs to see readings from 2 or more device types at the same time. To get around this, utilities in the United Kingdom started installing a single system to support operations of the distribution network in the last 1990's. This system was dubbed the Distribution Management System (DMS).

The goal of DMS is to display the information that an operator needs to make good decisions on what to change in the distribution system in order to keep the efficiency of the system optimized. With the advent of electric cars, distributed generation, demand response and other changes, the distribution system will become less of a passive one way system and more of a 2 way network. This change means that more active management of the power flow and the network configuration will be required.

Today much of the configuration is done by sending a person into the field to make a change. That change might take 15 minutes or it might take several hours depending on the urgency and availability of people. In the future changes might need to happen routinely, and the time to make the change might be as little as a few seconds. The DMS provides a single console that allows the operator to see the need for changes and send the right commands into the network to make the configuration changes that are required to support the optimization of the grid.

The DMS normally is fed from many other systems including the automated feeder system, the distribution automation system, the demand response system, and even the AMI system. This means that these systems have to be optimized to pass key control information to the DMS quickly.

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	Distribution management system required
Improved fault location	Distribution management system may enhance this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Distribution management system required
Dynamic Volt-VAR management	Distribution management system required
Conservation Voltage Optimization	Distribution management system required
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Distribution management system may enhance this application
Asset Condition Monitoring	Distribution management system may enhance this application

Costs:

Distribution management systems are estimated to cost hundreds of thousands of dollars.

Maturity:

Advanced distribution management systems are an emerging technology that are increasingly becoming more capable as utilities deploy more devices requiring coordinated control and monitoring.

Planning and Modeling System

Description:

This is a catch all of different applications, some of which may exist today and some may not within a utility. They cover a broad range of market and engineering requirements. Planning systems may range from planning the next new line into a new substation to planning of a demand response event. While there is a high probability that the system to support the new line exists within a utility, there is an equally high probability that the system to plan the demand response does not exist.

These systems have a tendency to be technical in nature and consume large amounts of data to determine the most probable answer to the question "what should we do about XX in the future?" Many of the systems are informal and developed in Excel spreadsheets to answer targeted questions on simple problems, others are wider ranging systems that have hundreds or thousands of rules and can consume millions of fields of information. Most of the existing systems for distribution tend to be on the simple side, with the more powerful systems reserved for transmission and generation. As the amount of data increases and the types of questions become more complex, the planning systems will grow in complexity.

Modeling systems also are used for a wide variety of purposes and like the planning systems cover a lot of ground. While planning systems tend to be built to answer one or two questions that are asked over and over again, modeling systems tend to be used to answer a wide range of "what if?" questions based on a well defined model.

The difference between the two types of systems tends to be in the amount of time to set them up and calibrate them, as well as the underlying software. Like simple planning tools, simple modeling tools can and are built in Excel. The more robust modeling tools are built in purpose designed modeling systems and then updated regularly as changes are made to the field.

Both sets of tools are very important in a dynamic grid to help operator and planners determine the right course of action.

Applications:

Application	Support
Demand Response Applications	
Price Information to In-Premises Devices	Planning and modeling system may enhance this application
Direct Load Control	Planning and modeling system may enhance this application
Distribution Automation Applications	
Automatic circuit reconfiguration	Planning and modeling system may enhance this application
Improved fault location	Planning and modeling system may enhance this application
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	Planning and modeling system may enhance this application
Dynamic Volt-VAR management	Planning and modeling system may enhance this application
Conservation Voltage Optimization	Planning and modeling system may enhance this application
System and Asset Monitoring and Modeling	
Asset Sizing Optimization	Planning and modeling system may enhance this application
Enhanced System Modeling and Planning	Planning and modeling system required
Distributed Resource Applications	
Coordinated Management of Distributed Resources	Planning and modeling system may enhance this application
Transmission Applications	
Wide Area (Phasor) Measurement	Planning and modeling system may enhance this application
Wide Scale Outage Recovery	Planning and modeling system may enhance this application

Costs:

Planning and modeling systems are generally a collection of more specialized software applications. Individual applications can range from tens to hundreds of thousands of dollars.

Maturity:

Planning and modeling systems are mature applications that continue to evolve as new sources of data are used by the utilities. Utilities and vendors are expanding the use of system models as AMI and other smart grid devices provide hundreds, thousands and millions of points of data from throughout the electrical system.

SCADA System

Description:

A SCADA (Supervisory Control and Data Acquisition) system is the communications “glue” between the operations control center and the devices which monitor and control the electrical power system. The SCADA system typically consists of a hierarchy of devices which collect and concentrate the information as it proceeds from the end devices to the control center.

The primary function for SCADA system is for both the real-time delivery of the status of the power system and the operations needed to control the power system operations. The collected information includes typical electrical parameters such as voltages and currents as well as meteorological information, physical security status (example, open substation gates), and the physical well-being of equipment (example, transformer temperatures). On the control side, the SCADA system acts to translate the requests from the control centers into actions taken at the end device. These requests may be sourced by manual actions of human operators or by automatic control systems.

The devices which directly communicate with the end devices include protective relays (which automatically control circuit breakers), measurement devices, control devices, human-machine interfaces (control panels), physical security access systems, and other devices. These are collectively known as IEDs (Intelligent Electronic Devices). The information from these devices may feed directly to the operations control center, but more typically feed into devices known as data concentrators. The data concentrators reduce the volume of information and also provide data protocol translations needed by upstream devices. The data is eventually communicated to the operations control center information infrastructure for further processing by applications. These applications include intertie billing, generation control, load forecasting, as well as other applications.

The SCADA system includes the underlying communications infrastructure needed to transport the data. The transport media can consist of shared or dedicated telephone lines, fiber optic links, microwave links, or radio frequency devices (radio modems).

Applications:

Application	Support
Distribution Automation Applications	
Automatic circuit reconfiguration	SCADA may be an element of this application. AMI networks may work in conjunction with SCADA to communicate data.
Improved fault location	SCADA may be an element of this application. AMI networks may work in conjunction with SCADA to communicate data.
Dynamic System Protection for Two-Way Power Flows and Distributed Resources	SCADA may be an element of this application. AMI networks may work in conjunction with SCADA to communicate data.
Dynamic Volt-VAR management	SCADA may be an element of this application. AMI networks may work in conjunction with SCADA to communicate data.
Conservation Voltage Optimization	SCADA may be an element of this application. AMI networks may work in conjunction with SCADA to communicate data.
System and Asset Monitoring and Modeling	
Asset condition monitoring	SCADA is an element of this application
Enhanced physical security	SCADA may be an element of this application
Distributed Resource Applications	
Coordinated Management of Distributed Resources	SCADA is an element of this application
Dispatch of Electric Vehicle Storage	SCADA may be an element of this application. AMI networks may work in conjunction with SCADA to communicate data.
Transmission Applications	
Wide Area (Phasor) Measurement	SCADA is an element of this application

Wide Scale Outage Recovery	SCADA is an element of this application

Costs:

The cost of SCADA systems vary to a large degree. The costs vary depending upon whether the communications infrastructure is specifically built for SCADA operations or whether shared resources can be used. SCADA master systems (the “box” in the operation center) range in price from $5000 for very small systems (such as that for a small municipal electric cooperative) to well over $1 million for very large electrical power systems with multiple generators. The data concentrator costs also have wide cost range from $1000 to $20000.

Another highly variable component of SCADA is the communication infrastructure. Costs depend strongly on factors such as:

- Geographical dispersion of the utility (urban vs. rural)
- Terrain (level vs. mountainous)
- Previously existing infrastructure

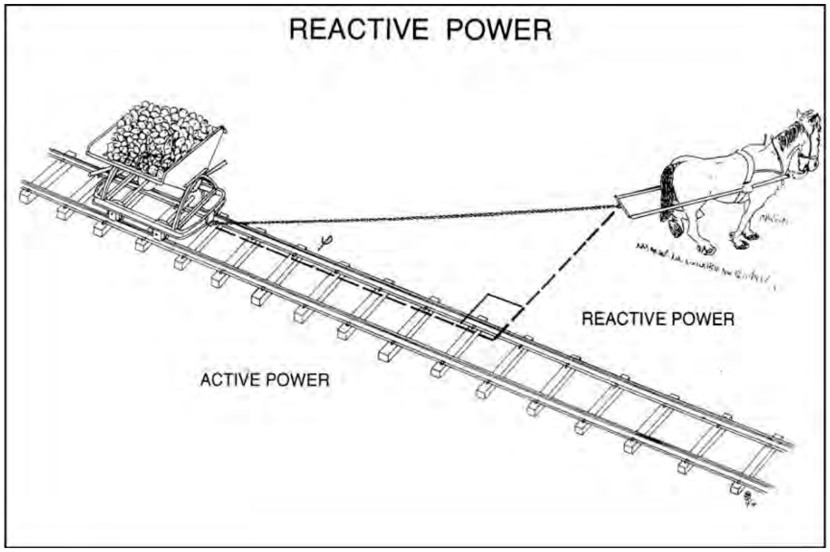
Maturity:

SCADA systems have been used for many decades. However, modern SCADA systems with wide-area control and monitoring began growing at an exponential pace starting in the 1970s with the advent of the microprocessor; which reduced the integration costs dramatically compared to individual point-to-point connections. Dozens of vendors offer SCADA master systems. Dozens of vendors offer communications infrastructure equipment. Hundred of vendors offer end-point devices.

SCADA systems are under continually improvement. This is driven primarily by the user needs for simplified interfaces and reduced maintenance costs (primarily due to the aging utility workforce). Unlike the more typical IT life cycles of a few years, SCADA life cycles are more typically 10-20 years.

Appendix A.1 – Reactive Power

Reactive power appears in all electric power systems. Contrary to active power, sometimes called true power, which is what we really want to transmit over our power system, and which performs real work, such as keeping a lamp lit or a motor running, reactive power does not perform any such work. Consequently, in a way one can say that the presence of reactive power in a grid results in a heavier or more burdened load for the delivery of active power, i.e. transmit power from A to B (Figure below), and consequently less efficient than would otherwise be possible. In this illustration, the closer the position of the horse is in relationship (parallel) to the tracks, thus reducing the angle of pull at the cart, the lesser the load and more efficient the task.

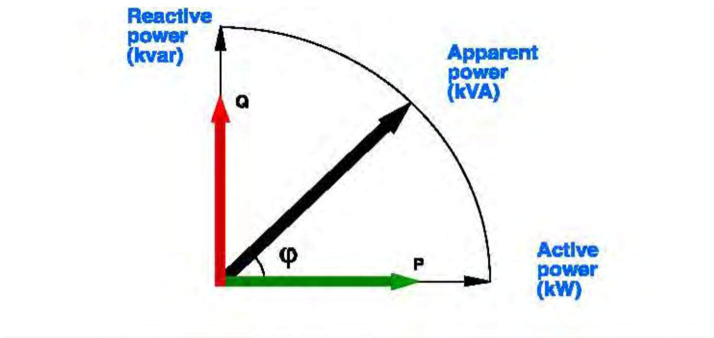


Similarly, if we can minimize the flow of reactive power over the transmission system, we can make the system more efficient and put it to better and more economical use. To accomplish this utilities add capacitor banks and other components (such as phase-shifting transformers; static VAR compensators; physical transposition of the phase conductors, etc.) throughout the system to control reactive power flow for reduction of losses and stabilization of system voltage.

We cannot altogether do without reactive power, though, because it is intimately linked with grid voltage (500 kV, 400 kV, 220 kV, etc). To get the correct grid voltage, we need the right amount of reactive power in the system. If there is not enough reactive power, the voltage will sag. And vice versa, if there is too much of it, the voltage will be too high. So, to have it in the right amounts at all times, and in the right places of the grid, is the task to be performed by reactive power compensators.

Reactive power balance is important also from another point of view: it ensures that valuable space in transmission lines and equipment such as transformers is not occupied by "idle" reactive power, but rather available for a maximum of useful, active power (Figure below). Remember, as illustrated in (Figure above) as Reactive Power is decreased the angle between

Apparent Power and Active Power shrinks and the burden on the system decreases resulting in greater system efficiency.



Reactive power steals precious space in power lines and equipment

Here it should be pointed out that a reactive power compensator needs to be fast, i.e. fast response is a key characteristic of the device. This is particularly crucial in situations when a fault appears in the grid. In such a situation, it will often be a matter of milliseconds for the reactive power compensator to go into action and help restore the stability and the voltage of the grid in order to prevent or mitigate a voltage collapse.

In general, it is quite common for a deficit of reactive power close to large, electricity consuming areas, as well as close to large, electricity consuming industry enterprises, such as steel works, petrochemical complexes, and large mine complexes. That means that in such cases, reactive power needs to be added. Vice versa, there is usually a surplus of reactive power at the end of long, lightly loaded transmission lines and cables. Here, reactive power may need to be compensated away. In both cases, and particularly when the reactive power is fluctuating with time, reactive power compensators can provide the solution.

Maintaining proper balance of reactive power in the grid is important also from another point of view: too much reactive power flowing in the grid also gives rise to losses. To prevent such losses, it is important that reactive power is not permitted to flow over long distances, because losses grow with the distance that the reactive power is flowing over. Instead, reactive power should be inserted where it is needed, i.e. close to large cities and/or large industry enterprises.

Appendix B: List of Collaborative Participants

The following list of Collaborative members includes individuals who signed up to participate in the Collaborative, or attended one or more of the Collaborative workshops and workgroups. This list does not indicate the level of participation.

Name	Company/Organization
Scott Musser	AARP
Barbara Alexander	Representing AARP
Ernst Scholtz	ABB
Ben Boyd	Aclara
Deborah Rachlis	Aclara
Mike Lamble	Albion
Michael S. Abba	Ameren Illinois Utilities
Bev Hall	Ameren Illinois Utilities
J. Bruce Hollibaugh	Ameren Illinois Utilities
Leonard Jones	Ameren Illinois Utilities
Rodger Koester	Ameren Illinois Utilities
Keith Martin	Ameren Illinois Utilities
Robert Mill	Ameren Illinois Utilities
Ron Pate	Ameren Illinois Utilities
Roger Pontifex	Ameren Illinois Utilities
Jacqueline Voiles	Ameren Illinois Utilities
Dave Costenaro	Ameren Services Company
Jeff Hackman	Ameren Services Company
Joe Ostendorf	Ameren Services Company
Matt Tomc	Ameren Services Company
Rick Voytas	Ameren Services Company
Cory Cipra	Arcadian Networks
Brian Adams	Association of Illinois Electric Cooperatives
Carl Dufner	Association of Illinois Electric Cooperatives
Mark Abruzzo	AT&T
James Deignan	AT&T
Latrelle Haynes	AT&T
Mackenzie Maloney	AT&T
Tom McClowry	AT&T
Deno Perdiou	AT&T
Greg Ward	AT&T

Name	Company/Organization
Cheryl Dancey Balough	Balough Law Offices, LLC
Richard C. Balough	Balough Law Offices, LLC
William C. Cole	Black & Veatch
Madelon Kuchera	BlueStar Energy Services, Inc.
Brian Collins	Brubaker & Associates, Inc. representing Illinois Industrial Energy Consumers
Robert Stephens	Brubaker & Associates, Inc. representing Illinois Industrial Energy Consumers
Michael Munson	Building Owners and Managers Association
Roy Ellis	CapGemini
Lawrence Sturm	CapGemini
Brad Emalfarb	Carbon Day
Hal Emalfarb	Carbon Day
Scott Emalfarb	Carbon Day
Brian Levin	Carbon Day
Bryan Villano	Carbon Day
Carl Peterson	Center for Business and Regulation
Lawrence J Kotewa	Center for Neighborhood Technology
Anne McKibbin	Center for Neighborhood Technology
Matthew Scallet	Center for Neighborhood Technology
Anthony Star	Center for Neighborhood Technology
Claire Woolley	Chicagoland Chamber of Commerce
Jerry Brown	Chico & Nunes, P.C.
Celia Christensen	Citizens Utility Board
Rebecca Devens	Citizens Utility Board
David Kolata	Citizens Utility Board
Evan La Ruffa	Citizens Utility Board
Bryan McDaniel	Citizens Utility Board
S. Moskowitz	Citizens Utility Board
Kristen Munsch	Citizens Utility Board
Julie Soderna	Citizens Utility Board
Chris Thomas	Citizens Utility Board
Annie Warnock	Citizens Utility Board

Name	Company/Organization
Ron Jolly	City of Chicago
Antonia Ornelas	City of Chicago
Conrad R. Reddick	Representing the City of Chicago
Brad Bjerning	Commonwealth Edison
Vic Chesna	Commonwealth Edison
James Crane	Commonwealth Edison
Dave Doherty	Commonwealth Edison
Jim Eber	Commonwealth Edison
Robert Garcia	Commonwealth Edison
Rich Gordus	Commonwealth Edison
Ross Hemphill	Commonwealth Edison
Algie Hill	Commonwealth Edison
LaShonda Hunt	Commonwealth Edison
Val Jensen	Commonwealth Edison
Dan Kowalewski	Commonwealth Edison
Michael Pabian	Commonwealth Edison
Susan Pagles	Commonwealth Edison
Mark Simon	Commonwealth Edison
Harpreet Singh	Commonwealth Edison
Mary Vincent	Commonwealth Edison
Dave Hyland	Comverge
Cynthia Fonner Brady	Constellation Energy
David Fein	Constellation Energy
Ellen C. Craig	Consultant
Dave Sullivan	Consumer
Jackie McCarthy	CTIA
Jason Kelly	CURRENT Group
Dave Mulder	CURRENT Group
Rick Walsh	CURRENT Group
Scott Stewart	Direct Energy
Cathy Yu	DLA Piper
Baiba Grazdina	Duke Energy
Jim Andrus	Echelon Corporation
Shane M. Fay	Echelon Corporation

Name	Company/Organization
Jason Denny	Elster
Kathleen Quasey	EMI
Erin Hollinshead	Energy Education Council-UIUC
Brian Granahan	Environment Illinois
Mark Brownstein	Environmental Defense Fund
Barry Matchett	Environmental Law & Policy Center
Mel Nickerson	Environmental Law & Policy Center
Doris Abernathy	EPRI
Bernie Neenan	EPRI
Matt Wakefield	EPRI
Stephen Bennett	Exelon
Doug McGinnis	Exelon
Mahesh Mikkilineni	Exelon
Brian Hoeger	Exelon Energy
Sheila Owens	Exelon Generation
Chris Miller	FERC
E. Glenn Rippie	Foley & Lardner LLP
Carla Scarsella	Foley & Lardner LLP
Josh Bode	FSC Group
John Kelly	Galvin Project
Greg Rouse	Galvin Project
BJ Asirvatham	GarretCom
Greg Blake	GE Energy
Frank Gerovac	GE Energy
George Bultmann	General Electric
Matt Thomson	General Electric
Ryan Wiltshire	General Electric
Robert W. Gee	Gee Strategies Group, LLC
Mel Gehrs	Gehrs Consulting, Inc
John Gomoll	Gomoll Government & Regulatory Affairs
Jeffrey Greenspan	Greenspan Law
Michael Leppitsch	Gridata
Justin Mamula	Groebner & Associates
Edward Tirakian	GWI Solutions

Name	Company/Organization
Mike Coop	heyCoop, LLC
Ed Gower	Hinshaw & Culbertson LLP
Joe Miller	Horizon Energy Group (NETL Smart Grid Implementation Team)
Brian Loomis	IBEW Local 15
David Wiggins	IBEW Local 15
Jett Anderson	IBEX Engineering Services
Dan Niswonger	IBM
Michael R. Borovik	Illinois Attorney General's Office
Janice Dale	Illinois Attorney General's Office
Susan Hedman	Illinois Attorney General's Office
Karen Lusson	Illinois Attorney General's Office
Jim Agnew	Illinois Commerce Commission
Alicia Allen	Illinois Commerce Commission
Gene Beyer	Illinois Commerce Commission
Nicholas Bowden	Illinois Commerce Commission
Sean Brady	Illinois Commerce Commission
David Brightwell	Illinois Commerce Commission
Torsten Clausen	Illinois Commerce Commission
Ambika Dalal	Illinois Commerce Commission
Christine Ericson	Illinois Commerce Commission
John Feeley	Illinois Commerce Commission
Carmen L. Fosco	Illinois Commerce Commission
Bud Green	Illinois Commerce Commission
Sheila Griffin	Illinois Commerce Commission
Louis Harris	Illinois Commerce Commission
Dianna Hathhorn	Illinois Commerce Commission
John Hendrickson	Illinois Commerce Commission
Jennifer Hinman	Illinois Commerce Commission
Peter Lazare	Illinois Commerce Commission
Randy Nehrt	Illinois Commerce Commission
Rochelle Phipps	Illinois Commerce Commission
Christy Pound	Illinois Commerce Commission
Yassir Rashid	Illinois Commerce Commission

Name	Company/Organization
Greg Rockrohr	Illinois Commerce Commission
John Sagone	Illinois Commerce Commission
Eric Schlaf	Illinois Commerce Commission
Brian Sterling	Illinois Commerce Commission
Scott Tolsdorf	Illinois Commerce Commission
James Zolnierek	Illinois Commerce Commission
Kevin Wright	Illinois Competitive Energy Association
Dave Bieneman	Illinois Department of Employment Security
Patrick Evans	Illinois Energy Association
James Monk	Illinois Energy Association
Steve Frenkel	Illinois EPA
Mark Pruitt	Illinois Power Agency
Jordan Cutler	Illinois Science & Technology Coalition
Kurt Schurecht	Independent Consultant
Wayne Bollinger	Integrys Energy Services
James Fahey	Integrys Energy Services
Esther Kang	Integrys Energy Services
John Bourguignon	Intergraph
Dan Pfeiffer	Itron
Rasheed Joshi	Jahan Analytics
Hank Kelly	Kelley Drye & Warren LLP representing T-Mobile
Julie Oost	Kelley Drye & Warren LLP representing T-Mobile
Dennis Friend	KEMA Inc.
Darren Bronaugh	KenJiva Energy Systems
Mark Handy	KenJiva Energy Systems
Joe Jaskulski	Kenny Construction
Bogdan Bosak	Kenwood Group LLC
Troid Edwards	Landis+Gyr
Clark Pierce	Landis+Gyr
Michael Vecchi	Landis+Gyr
Laura Kratz	League of Women Voters

Name	Company/Organization
Greg Diamond	Level 3 Communications
Robert Jepson	Lockheed Martin
Young Joo Lee	LS Industrial Systems
Eric Robertson	Lueders, Robertson & Konzen, LLC representing Illinois Industrial Energy Consumers
Ryan Robertson	Lueders, Robertson & Konzen, LLC representing Illinois Industrial Energy Consumers
Sharon Hillman	MC Squared representing Illinois Competitive Energy Association
Mark McGuire	MC Squared representing Illinois Competitive Energy Association
John S. Guzik	Meade Electric Company
Bob Schacht	Meade Electric Company
Jack Bauer	METRA
Anthony Ognibene	METRA
Thomas Stuebner	METRA
Kate Agasie	Metro Mayors Caucus
Namoi Czachura	MidAmerican Energy
Anne McGlynn	MidAmerican Energy
Peter J Schuster	MidAmerican Energy
Gregory Ehrendreich	Midwest Energy Efficiency Alliance
Joyce Davidson	Midwest ISO
Vijaya Ganugula	Midwest ISO
Todd Hillman	Midwest ISO
Richard Kalisch	Midwest ISO
John-Paul H. Knauss	National Grid
Raymond Chung	National Technical Systems
Dylan Sullivan	Natural Resources Defense Council
Karen Hobbs	Representing NRDC
Jerry Bolgren	Nicor Gas
Sharon Grove	Nicor Gas
Bart Hill	Nicor Gas
Pamela L. Tuburan	Nicor Gas

Name	Company/Organization
Kate Tomford	Office of Governor Pat Quinn
Matt McCaffree	Opower
Ran Nussbacher	Opower
Eric Hale	Patrick Energy Services
Amy Rainwater	Patrick Energy Services
Ken Huber	PJM Interconnection
Richard Mathias	PJM Interconnection
Kerry Stroup	PJM Interconnection
Kim Wall	PPL Corporation
Keith Kalinowski	Quebec Delegation Chicago
Tim Wolf	R.W. Beck
Scott H. DeBroff	Rhoads & Sinon LLP
Monica Iino	Rhoads & Sinon LLP
Alicia Petersen	Rhoads & Sinon LLP
Steve Moore	Rowland & Moore LLP
Randy Gucwa	S&C Electric Company
Dave Kearns	S&C Electric Company
Mark Mooney	S&C Electric Company
Rochelle G. Skolnick	Schuchat, Cook & Werner
Michael Thomas	Secure Bio
Bob Old	Siemens
Michael Jung	Silver Spring Networks
Sameer Kalra	Silver Spring Networks
Tom Luecke	Silver Spring Networks
Alison Silverstein	Silverstein Consulting
Tam Do	Southwest Research Institute
Reggie Greenwood	SSMMA
Martin Coyne	Strategic Communications, LLC
David Blodgett	Telvent Miner & Miner
Steve Bonifas	Telvent Miner & Miner
Steve Williams	Telvent Miner & Miner
Cameron Brooks	Tendril Networks
Rex Irby	The Computer Guy
Daryl Thompson	Thompson Network Consulting

Name	Company/Organization
Garnet Hanly	T-Mobile
Ryan Keefe	T-Mobile
Rolf Bienert	TUV Rheinland of North America
Daniel Baksht	University of Chicago (student)
Alejandro Dominguez-Garcia	University of Illinois
Keith Erickson	University of Illinois
Carl Gunter	University of Illinois
Himanshu Khurana	University of Illinois
Michael LeMay	University of Illinois
Vince Molina	University of Illinois
Thomas J. Overbye	University of Illinois
William H. Sanders	University of Illinois
Gene Waas	University of Illinois
Tim Yardley	University of Illinois
Ray Klump	University of Illinois & Lewis University
Hans Gruber	UnixWorks
Rory Lewis	Ventyx
Mike Brander	Verizon Wireless
Gary R Moschetta	Verizon Wireless
David Cook	Village of Hinsdale
Chris Ragona	Village of Hinsdale
Dave Strahl	Village of Mount Prospect
Robert Cole	Village of Oak Park
K.C. Poulos	Village of Oak Park
Dale Schepers	Village of Tinley Park
Timothy Frenzer	Village of Wilmette
Dan Belmont	West Monroe Partners
Liana Cipcigan	
Alon Gavrielov	
Dan Lubar	
Niall McShane	
Clifton Muhammad	
Robert Neumann	

Appendix C:
Relevant Section of the Illinois Commerce Commission (ICC) Order

Appendix C – Excerpt of Illinois Commerce Commission Order 07-5666

This Appendix to the Collaborative Report is an extract from the Illinois Commerce Commission's Order in Docket No. 07-0566 of September 10, 2008 which authorized the Illinois Statewide Smart Grid Collaborative. The extract begins with Chapter VII (New Riders), Section B (Rider SMP – Systems Modernization Projects Adjustment), Item 16 (Commission Analysis and Conclusion). The full text of the Order, including summaries of testimony by parties, can be downloaded from the ICC website at http://www.icc.illinois.gov/docket/files.aspx?no=07-0566&docId=128596&m=0**.**

Commission Analysis and Conclusion

The Commission commends ComEd for its initiative in pursuing smart grid and AMI. Staff witness Schlaf described many of the operational and societal benefits of AMI, *i.e.*, reduced headcount for meter readers, fewer field visits to restore power outages, less time fielding customer complaints, minimizing future generation costs, reduced need for upgrades and investments to ComEd's transmission and distribution systems and also environmental benefits. Some of these environmental benefits are possible through reduced power plant emissions and fewer vehicles on the road.

RESA, in its Reply Brief, states that "if the AMI works as we believe it should, the result of using electricity more efficiently should help delay the need for new generation, make existing generation more efficient, and could even result in a decline in the amount of generation used per customer."

Several Intervenors suggest that ComEd's proposal is in violation of the Commission's basic service rules, but the evidence in this proceeding suggests that parties only raise this argument in the context of rider recovery of these investments. In other words, these parties do not object to these projects being included in rate base. Staff witness Linkenback stated his disapproval of rider recovery because the Company is already investing in these projects, *i.e.*, SCADA, and recovering the cost through rate base. Yet, he immediately followed this claim with a discussion of how it is inappropriate to recover these costs through Rider SMP because they go beyond basic service requirements. Staff Ex. 19.0 at 19-20. There is an inconsistency here. If ComEd should not be able to recover these costs through a rider, because they are above and beyond basic service, then the Company likewise should not be able to recover these costs through base rates. Because no party has argued against including these projects in rate base, it undermines any argument that these projects go beyond basic service requirements.

There is some argument to suggest that smart grid does not satisfy the Commission's least cost standards. Our least cost requirements, however, do not require that electric service be the most simple, basic, and cheapest form of electric service available. The least cost provisions require that the chosen electric service be provided in the least cost manner. So, for our purposes here, the least cost provisions would require that the smart grid installed be at least cost, *i.e.*, the various components must be optimized to provide maximum benefits to consumers, subject to competitive bids and the labor must be provided at competitive rates.

The Commission service rules do not contain a prohibition on investing to improve service or a bar to providing more beneficial services. Indeed, they contain minimum and not maximum requirements. A rewrite of our rules has not been shown to be necessary in order for an electric utility to recover its investment in smart grid through either base rates or a rider.

The Commission very recently analyzed the legal precedent regarding the Commission's authority to approve riders in the Peoples Gas rate case when considering proposed Rider VBA. Dockets 07-0241/07-0242 (cons.). Without restating that analysis, it is clear that we have the authority to adopt the rider mechanism in proper situations and under circumstances that are lawful and reasonable. In fact, smart grid may be just the sort of investment that is appropriately recovered through a rider.

While the Commission has the authority to approve riders, each subject underlying situation and design require a particularized analysis. In this instance, the Commission believes that it must first determine how smart grid should be deployed in Illinois, and then determine whether and to what degree it is necessary to approve a particular cost recovery mechanism. Lacking an overall goal for Illinois, Rider SMP simply promotes a project by project approach. Further, although ComEd has agreed to a workshop process, it would still retain sole discretion in determining what projects are ultimately proposed to the Commission.

Similarly, without an overall plan for smart grid deployment and without any specific projects being proposed, the Commission does not know the extent of the costs and benefits involved, with the possible exception of Phase 0. The estimates of costs in the record have varied greatly and the estimates of benefits have been sporadic at best. This lack of cost and benefit information is a problem that is not overcome by the process proposed for Commission pre-approval of specific projects. Our hope is to have a better grasp of costs and benefits once Phase 0 is implemented and analyzed, as discussed below.

The lack of a consistent, thorough and analytic approach to estimating benefits simply highlights another shortcoming: ComEd is asking for special recovery for these projects that – whatever their level, all parties agree -- could have long-term economic benefits, but as proposed, ratepayers do not share the economic benefits. It is not clear that the earnings cap, with all its potential for disagreement, adequately answers this concern. Another concern about the process that was raised by many parties is that they would be overburdened by the workshops, pre-approval dockets, earnings cap and prudence review dockets and the real possibility of additional rate cases by ComEd.

With these concerns in mind, Rider SMP is approved, as discussed in the section below, and for the very limited purpose of implementing Phase 0 – a scaled deployment of AMI – as a pilot program. Rider SMP is also subject to the conditions that Staff witness Hathhorn proposed in her testimony, and as revised and accepted by ComEd in its surrebuttal testimony. Phase 0, however, is only the first step. A broader plan is needed to develop a policy framework and to address parties' concerns that there is no well structured plan with identified costs and benefits. To address this need ComEd, CNE, CUB, and Staff propose various collaborative processes. From these proposals, CUB seems to outline the best proposal for a statewide smart grid collaborative.

a) Phase 0

Phase 0 is primarily the installation of up to 200,000 advanced meters and associated infrastructure. There are a number of tasks that need to be completed to ensure the success of this pilot program. As discussed in more detail below, these tasks are: the formation of a workshop process ("AMI Workshops") led by an independent third-party facilitator; the development of goals, timelines, evaluation criteria, etc. in the AMI Workshop process; the docketed proceeding approving AMI deployment and cost recovery; the installation of AMI; the monitoring of and data collection of AMI performance; and the production of reports to the Commission on the progress and results of Phase 0. In addition, all of this is to be coordinated with a Statewide Smart Grid Collaborative process, discussed below.

ComEd witness Clair testified that Phase 0 will enable the Company to quantify the costs and benefits of full AMI deployment. While the Commission understands how the proposed Phase 0 will allow ComEd to quantify the costs of a full AMI deployment, the process by which ComEd quantifies the benefits remains unclear. The AMI Workshops, described below, shall fully investigate the measure of benefits from the utility side of the meter.[50] Ms. Clair also testified that, after deployment of AMI, ComEd will be able to analyze certain aspects of AMI's performance and operation. Therefore, following the deployment of AMI and a period of analysis that is extensive enough to enable ComEd to evaluate Phase 0, ComEd is directed to prepare a report assessing the results of Phase 0. ComEd is directed to make this report available to the Commission and the Statewide Smart Grid Collaborative, which is described below, because analysis of Phase 0 is one of the issues to be addressed in the Statewide Smart Grid Collaborative. Therefore, the AMI Workshop cannot conclude until ComEd has prepared the Phase 0 evaluation report and the AMI Workshop participants have had an opportunity to review the report.

As proposed, Phase 0 of the plan for AMI deployment would be limited to roughly 200,000 customers with the expectation that meters will be installed by the end of 2009. The Commission's expectation is that the actual field testing and analysis of the Phase 0 may take an additional 12 months, though we acknowledge these timelines may be changed in future proceedings. ComEd may submit Rider SMP through a separate compliance filing so that Rider SMP for Phase 0 will be effective no later than October 1, 2008.

The Commission directs that the AMI Workshop process, as proposed by CNE witness Fein and refined in the surrebuttal testimony of ComEd witness Crumrine, begin as soon as practicable to develop project goals, timelines, evaluation criteria and Phase 0 technology selection criteria. Because the Commission is adopting Rider SMP for the limited purpose of a pilot program (Phase 0), the Commission perceives no need for the biennial filing schedule (whereby ComEd would file for approval of new projects and the continuation of existing projects every two years). If, in subsequent proceedings, the Commission decides to continue with AMI and smart grid proposals beyond Phase 0 then the need for a biennial filing schedule can be reevaluated. CNE and ComEd state that the AMI workshop process could be completed in about six months. The Commission finds that time period to be reasonable. If more time is necessary, a request for more time can be brought to the Commission.

CUB proposes, and ComEd does not object, that a third-party facilitator be employed to direct the workshop process. The Commission agrees with CUB and finds the use of a third-party facilitator to be important and appropriate. Accordingly, all interested parties may submit recommendations to the Executive Director of the Illinois

[50] Potential customer side benefits necessary to perform a cost-benefit analysis shall be analyzed in the Statewide Smart Grid Collaborative.

Commerce Commission ("Executive Director"), or his designee, for a third-party facilitator. The Executive Director, or his designee, shall then solicit the information needed to make a decision and select the candidate determined to be the most qualified third-party facilitator. The Executive Director, or his designee, shall then notify ComEd of the selected candidate. ComEd shall retain the services of that candidate as the third-party facilitator. In addition, the Commission finds it necessary to be kept apprised as to the progress of the AMI Workshops, therefore, the third-party facilitator shall report to the Commission every ninety days on the progress of the AMI Workshops.

Due to the fact that the exact scope of the Phase 0 project will be defined in the AMI workshops, the Commission is not approving a recovery of specific costs in this Order for Phase 0. In order to recover its costs through Rider SMP, ComEd must file a request for approval of the Phase 0 project after completion of the workshop process. In addition, the request will also require the Commission's approval of the goals, timelines, evaluation criteria, etc., that were developed in the workshops. At the time that ComEd requests approval of Phase 0, the Commission will address the amortization period for the meters that will be retired.

The annual reconciliation proceeding, as proposed by the Company, will examine the reasonableness of Phase 0 project costs. In this docketed proceeding, the Commission will review ComEd's earnings to determine whether Rider SMP refunds are in order (not to exceed the amount of SMP surcharges) if it is determined that the Company's reported earnings exceeded the rate of return established in this rate case.

b) Statewide Smart Grid Collaborative

The Commission recognizes that AMI deployment alone will not produce the benefits of a comprehensive digital smart grid. Furthermore, the Commission does not want – through an inadvertent sequencing of proposals, pilot projects, policy decisions and workshops – to unnecessarily delay implementation of the broader set of digital tools comprising the smart grid. And yet, at the same time, the Commission believes that smart grid deployment should not be a matter of haste. Our concern here is that under the Company's proposal we are being asked to quickly approve various improvements that resemble a smart grid, yet the Commission has insufficient information to assess if these improvements actually qualify as smart grid. Under these circumstances, if the Commission adopts Rider SMP too quickly and without sufficient stakeholder input or Staff analysis, the Commission would not be sure that consumers are the primary beneficiaries.

The potential benefits of a smart grid are such that smart grid and AMI topics should be pursued and considered by the Commission in a deliberate and thorough yet expedited manner. The clear direction of federal policy, as embodied in the EISA, is for states to consider smart grid topics. According to Staff witness Schlaf, the Commission must open proceedings to consider the two EISA smart grid ratemaking standards by December 19, 2008 and conclude its investigations by December 19, 2009. Staff Ex. 9.0 at 6. It is not clear that the EISA proceeding is the proper vehicle.

The Commission agrees with CUB, that a Statewide Smart Grid Collaborative process could adequately address the concerns expressed above. Therefore, a Statewide Smart Grid Collaborative involving the two large investor owned utilities regulated by this Commission, other stakeholders and Staff shall be initiated outside of this rate case during which the participants and the Commission can consider the costs and benefits of smart grid implementation and develop a strategic plan for such implementation for presentation – upon completion and in a docketed proceeding – to the Commission. The AMI Workshop and the Statewide Smart Grid Collaborative are to be initiated contemporaneously. While the AMI Workshop will be concluded in a relatively short period of time (six months), the Statewide Smart Grid Collaborative shall be conducted within twenty-four months of October 1, 2008. If it is determined that more time is necessary, that request can be brought to the Commission.

The purpose of the Statewide Smart Grid Collaborative is to develop a strategic plan to guide deployment of smart grid in Illinois, including goals, functionalities, timelines and analysis of costs and benefits, and to recommend policies to guide such deployment that the Commission can consider for adoption in a docketed proceeding. The analysis of benefits shall include reductions in utility costs related to maintaining and operating a distribution system as well as potential changes in consumer costs related to decreased energy consumption, reduced procurement costs, and increased price responsiveness and demand response.

We agree with CUB that the collaborative process should address foundational policies, as well as incorporate utility-specific issues. The policies that are to be considered in the Statewide Smart Grid Collaborative include, but would not be limited to: 1) definition of a smart grid and its functionalities; 2) principles Illinois should use to guide smart grid planning and deployment, for example, interoperability, open architecture, and non-discriminatory access; 3) uniform standards; 4) methods of estimating, calculating and assessing benefits and costs, including evaluation of non-quantifiable benefits (and costs); 5) implications of smart grid technology for future policies regarding rate design, consumer protection, and customer choice; 6) effect of statutory renewable resource, demand response and energy efficiency goals on smart grid planning and implementation; 7) consumer education and dissemination of information about smart grid technologies, demand response programs and alternative rate structures; 8) access by electricity market participants to smart grid functionalities; 9) data collection, storage, management, security, and availability to third parties; ~~9~~10) standards for interconnection of third party equipment; 11) mechanisms to flow through to customers any utility smart grid revenues; 12) adoption of new demand response programs; and 13) open architecture and inter-operability standards for technological connectivity to the RTO and/or ISO to which a utility may belong. CUB makes clear that many of these policy issues have been considered in national, regional and other statewide forums. To ensure efficiency in addressing the foundational policies, the Commission encourages the facilitator and attendees to incorporate this knowledge and information gained from these other processes into the Collaborative discussions, where practicable.

As the Commission directed previously, with regard to the AMI Workshops facilitator, a third-party facilitator ("Facilitator") shall also direct the Statewide Smart Grid Collaborative. Accordingly, all interested parties may submit recommendations to the Executive Director, or his designee, for a Facilitator. The Executive Director, or his designee shall then solicit the information needed to make a decision and select the candidate determined to be the most qualified Facilitator. The Executive Director, or his designee, shall then notify utility participants in the Collaborative of the selected candidate. The two utility participants shall retain the services of that candidate as the Facilitator. The Commission shall retain hiring and firing authority of the Facilitator. The Facilitator shall report to the Commission every ninety days on the progress of the Statewide Smart Grid Collaborative. At such time, the Facilitator will report any consensus items as well as any areas of disagreement. At the end of the Statewide Smart Grid Collaborative, the Facilitator shall prepare a report ("Collaborative Report"). The Collaborative Report is the product of the Statewide Smart Grid Collaborative's work and shall include a proposed smart grid vision for Illinois, summarize the foundational policy issues discussed in the Collaborative, recommend a policy framework for achieving that vision and recommend steps toward implementation. The Collaborative Report shall be publicly submitted to the Commission for consideration.

ComEd will pay its share of the expenses associated with the Statewide Smart Grid Collaborative. If applicable, the Commission may approve the use of grant money to pay the costs of the Statewide Smart Grid Collaborative. The Facilitator shall include in its ninety-day progress reports a discussion of the availability of grants and potential avenues for applying for those funds.

In its Brief on Exceptions, BOMA contends that the PO fails to recognize its concerns regarding the availability of information. The Commission finds, however, that these concerns are more appropriately addressed in the AMI Workshops and Statewide Smart Grid Collaborative.

Following the Statewide Smart Grid Collaborative, the Commission will open a smart grid proceeding ("Smart Grid Policy Docket") to consider the Collaborative Report provided by the Facilitator. In this proceeding, the Commission may adopt the policy framework developed in the Statewide Smart Grid Collaborative in whole or in part, or modify said policy framework. Any outstanding issues among the parties can also be resolved in this proceeding.

c) Smart Grid Implementation Docket

The Commission finds that the Company may re-file Rider SMP (or more appropriately Rider SG – Smart Grid) after the completion of Phase 0 and the Smart Grid Policy Docket. Renaming the rider to Smart Grid clarifies for consumers what they are paying for and also explicitly limits the rider to smart grid investments. With that filing, the Company should be prepared to explain how it will implement projects and plans consistent with the findings and policy framework for smart grid deployment approved in the Smart Grid Policy Order. ComEd shall also present the cost benefit analysis and other information that the Commission sought in the Peoples Gas proceeding (Docket 07-0241/07-0242). Among other things, the Company should show whether the earnings cap is the appropriate method to capture the benefits for consumers and the impact of rider approval on its cost of capital for those projects.

ComEd witness Crumrine stated in his rebuttal testimony that

> in the event the Commission orders separate processes be undertaken to further consider Smart Grid technologies, such as those proposed by Staff or CUB, many of the threshold issues already will have been addressed by the parties in those processes. Thus, less time should be required to consider these issues in future approval proceedings." ComEd Ex. 30.0 at 14.

The project-by-project consideration may be appropriate, but only in the context of overall smart grid goals approved in the Smart Grid Policy Order. When the Company re-files Rider SMP/SG, appropriate process changes should be addressed.

In summary, Rider SMP is adopted for the limited purpose of implementing Phase 0 of AMI deployment, following the six month AMI Workshops and Commission approval, as discussed above. The results of Phase 0 will be analyzed by ComEd and brought to the Statewide Smart Grid Collaborative. The Statewide Smart Grid Collaborative should begin to immediately consider smart grid policy issues in Illinois. That collaborative process is to be followed by a Commission docket to adopt specific goals and policy framework related to the deployment of a smart grid in Illinois. Thereafter, ComEd may file a plan for implementation and re-file its request for rider recovery of smart grid investments.