Smart Grid Inventory

Prepared by

Robert J. Procter

for

Commissioners Ackerman and Savage
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Contents

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- American Public Power Association
- Cooper Power Systems
- Department of Environment, Government of Saskatchewan, Canada
- Electric Power Research Institute
- Institute Public Utilities, Michigan State University
- National Association of Regulatory Utility Commissioners
- National Council of State Legislatures,
- National Regulatory Research Institute
- Pacific Northwest National Labs
- Regulatory Assistance Project
- Schweitzer Engineering Laboratories
- U.S. Department of Energy: BPA, Smartgrid.gov

Smart Grid Investment Inventory

On May 25, 2011, the Commissioners (Commissioners) of the Oregon Public Utility Commission (OPUC) issued an Interim Order No. 11-172 (Interim Order) in docket UM1460. That Interim Order called on staff of the OPUC to develop an inventory of smart gird investments (Investment Inventory) and hold a series of workshops to gather additional information for the Commission. This is staff's report (Report) that includes the Investment Inventory recommendations and a series of appendices containing back-up materials.

Direction from the Interim Order

The Interim Order requires staff to compile "…an inventory of smart grid investments that may be made in the next three to five years that could benefit Oregon utility customers."[1] The Interim Order also states that "The Commission intends to use this inventory of current and potential smart grid investments for two purposes: (1) to inform our decision about what planning requirements and guidelines, if any, to establish later in these proceedings; and (2) to begin to identify the smart grid investments that utilities should consider and evaluate on an ongoing basis."[2]

Defining Smart Grid

Various approaches have been taken to 'defining' what is meant by SG. The Interim Order defines it as follows: "Utility investments in technology with two-way communications capability that will (1) improve the control and operation of the utility's transmission or distribution system, and [or] (2) provide consumers information about their electric use and its cost and enable them to respond to price signals from the utility either by using programmable appliances or by manually managing their energy use."[3](Note: distinction between programmable

[1] Before the Public Utility Commission of Oregon, Staff Recommendation to Use Oregon Electricity Regulators Assistance Project Funds from the American Recovery and Reinvestment Act of 2009 to Develop Commission Smart Grid Objectives for 2010-2014, pg. 3.
[2] Ibid.
[3] Before the Public Utility Commission of Oregon in UM1460, Order 11-172, May 25, 2011, p. 2.

and manually manage pertains to consumer's level of involvement that's needed)

Like most 'definitions' of smart grid, the one from the Interim Order is a list of features, or what I term applications. That is, a list of things a smart grid can or should do. This is actually about the best that can be done in terms of 'defining' smart grid. There really isn't any way to corral the SG concept into a pithy one liner (or two-liner). As the Commission alluded to in its Interim Order, it can be quite challenging to distinguish SG investments from non-SG investments. It alluded to this dilemma when it said, "In general, the Commission believes that smart grid investments are not materially different from any other utility investment made to provide service."[4]

Some states have 'defined' smart grid while others have not. The United States Department of Energy (USDOE) avoided defining SG. Rather, it articulated a set of capabilities. According to USDOE, the list of capabilities of smart grid is as follows:

(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;

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[4] Ibid, p. 2.

(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.[5]

This list from the Energy Independence and Security Act (EISA) of 2007 illustrates the challenge in getting a handle on smart grid. It’s a combination of activities that cuts across the entire breath of the power system. It encompasses everything associated with the full range of the electric system: generation, delivery, consumption, planning, billing, operations, not to mention systems on the customer side of the meter where utilities rarely have tread (except for conservation). It’s as though we’re at the dawn of the power system and we have to put the thing together. That’s what’s happening in smart grid. That is, smart grid is so unwieldy because it’s the answer to the following question: if you were designing a new power system, what combinations of applications, hardware, and software would you want in order to produce, distribute, monitor, and use electricity in a cleaner and more efficient way?

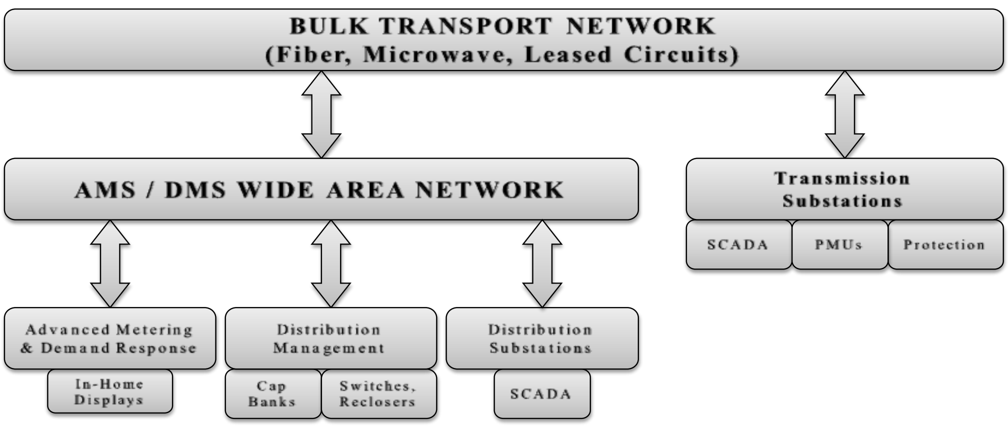
Communications – the Brains of Smart Grid

One conclusion staff has reached is that communications is such an essential part of SG that it deserves to be addresses separately. With that said, it’s quite challenging identifying a dividing line between communications and non-communications technologies. That difficulty underscores the degree to which SG technological investments are inextricably communications related, even

[5] http://www.oe.energy.gov/DocumentsandMedia/EISA_Title_XIII_Smart_Grid.pdf

when they some component is not strictly a communications technology. Staff is also supportive of the work done by PacifiCorp, especially its concurrence with staff's conclusion on the central role played by the SG communication system. They too concluded that "The backbone of a successful smart grid operation is a reliable, resilient, secure and manageable communication infrastructure."[6] In addition, they have a concise schematic for the communications network.[7]

Smart Grid Communications Network



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The three categories of communications related technologies laid out in the NSTC Report segment communications technologies into three logical 'bins.' These three bins, or categories, are:

1. *Advanced information and communications technologies* (including sensors and automation capabilities) that improve the operation of transmission and distribution systems;
2. *Advanced metering solutions*, which improve on or replace legacy metering infrastructure; and,

[6] PacifiCorp, *"Report on Smart Grid Technologies,"* p. 10.
[7] Ibid, p. 11.

3. *Technologies, devices, and services that access and leverage energy usage information*, such as smart appliances that can use energy data to turn on when energy is cheaper or renewable energy is available."[8]

Identifying a Smart Grid Investment Inventory

This Report contains an inventory of SG-related investments, as of the date of this Report that has been made by utilities nationally. You will note that PGE, PacifiCorp, and Idaho Power are mostly omitted from this inventory. They have been omitted since the Commission has directed them to file separate reports describing their smart-grid related activities.

While the Interim Order addressed a three to five year timeframe, staff has not limited itself to the next three to five years for several reasons. First, this docket has proposed that a utility's Smart Grid Plan (SGP) covers a 10-year period broken into two periods, a five –year Action Plan followed by a less detailed five year period. Second, what SG investments may by supported by a business case analysis is outside the scope of UM1460, and as a result, staff did not want to artifically constrain the Investment Inventory.

Using this Investment Inventory to Make Utility-Specific Recommendations

According to a recently released report from the Executive Office of the President of the United States (NSTC Report)[9], there are more than 3,000 electric utilities in the United States. The NSTC Report rightly notes that these utilities will have diverse needs, regulatory environments, energy resources, and legacy systems. Given the significant differences in sales size, customer distribution, size of service areas, generating plant mix, miles of transmission and distribution, and the age of these and other system components, grid modernization activities will

[8] Ibid, p. 1.

[9] A Policy Framework for the 21st Century Grid: Enabling our Secure Energy Future, released June 2011, by the Executive Office of the President, and prepared by the National Science and Technology Council, June 2011.

progress differently from utility to utility due to differences on these, and other factors that influence investment decision-making.

Diversity in existing electric systems, and existing communications infrastructure to support those systems, means there is no "one size fits all" solution. Among the factors that need to be considered include the flexibility to accommodate different physical requirements, legacy systems, Company goals, how the overall communications infrastructure is upgraded, and financial considerations.

Buxton and Mohseni argue that technology selection is arrived at through careful consideration of the utility's smart grid goals which, in turn, form the foundation of its business cases and design of its SG-related programs.[10] They suggest that while different utilities approach SG from various perspectives, each utility must consider and incorporate both short-term needs and longer-term opportunities. They suggest that the SG strategy needs to include a long-term phased approach that considers technology choices as part of program rollouts that reflect the utility's functional competencies and business case elements. Ideally, this rollout occurs in a way that supports longer-term SG goals.

Both the NSTC Report along with the Buxton & Mohseni paper point to at least some of the reasons staff is not making utility-specific recommendations. Additionally, fashioning a set of specific recommendations for a given utility for a given timeframe presents such a significant time commitment that it is not achievable within the time allotted to respond to the Interim Order and also allow parties in this docket to review drafts. Another problem with identifying a proposed set of utility specific investments is the ambiguity about which of these investments even have 'legs,' given the heavy subsidization using ARRA monies. Considering the complexity involved in making utility-specific recommendations, staff has consulted with Commission management about how to proceed.

[10] Jeff Buxton and Mehrdod Mohseni, *"Smart Grid – Different flavors for Different Tastes," See:* Intelligentutiltiy.com,

Commission management advised staff to identify investments that appear more often than others as staff looks at SG investments of utilities across the country. There is no ordinal or cardinal ordering implied.

Staff Recommendation

A utility's first Smart Grid Plan (SGP) will, at a minimum, include an evaluation of each potential investment in the Investment Inventory in Table One.

Table One - Investment Inventory[11]

I. **Customer Information and Energy Management**
Advanced Metering Infrastructure (AMI), or a system to collect meter data at intervals of one hour or less that is also able to inform customers of time-varying electric prices and provide timely (no more than 1-day lag) usage data, Building Energy Networks, Meter Data Management System, Direct Load Management

II. **Transmission & Distribution Control, Measurement, Monitoring**
Transmission Synchrophasors, Automated Distribution Systems, Integrated volt-VAR control, Substation Automation, SCADA Upgrades

III. **Communications and Supporting Systems**
Communications upgrades between all digital devices, equipment to support T&D digital upgrades, any needed software and back office systems support.

That evaluation will address any and all SGP guidelines adopted by this Commission. Table One may be revised at a later date as technologies evolve and greater experience is gained with SG investments.

PGE Alternative

PGE proposed that each utility be able to diverge from Table One and proposes the following language: "The intent of Table One is to act as a tool to guide a comprehensive review of possible SG investments by the utility. As the industry experience with SG implementation matures, alternative and improved tools to

[11] Appendix A organizes utility SG-related investments by the categories used in Table One. All terms are defined in Appendix B. Since various utilities sometimes use different terms to identify their activities, Appendix B contains terms that overlap. For example, distribution automation includes a host of specific actions. Appendix B includes a definition for distribution automation along with definitions of specific components of it. Staff has not had the time to go through all this information to arrive at one set of terms.

aid such a review are likely to result. The utility is welcome to report its next investment steps using an alternative inventory tool that has found industry acceptance."

Turning to the remainder of this Report, Appendix C focuses on the role of communications in SG investments. Appendix D, E, and F lists transmission, distribution, and customer investments, respectively. Appendices G and H list a variety of investments made by utilities that are regional in nature and/or include a whole host of specific components. Appendix I focus is solely on storage demonstration projects. Finally, in staff's view, rates and rate design are an essential part of SG. As such, staff has included Appendix J that summarizes a whole host of rate design experiments, pilots, and in some cases, actual tariffs in place by utilities in a variety of states across the country. Since the Interim Order did not direct staff to include rate related actions as part of a utility's SGP, no rate design recommendations are included in Table One.

Appendix A - Utility Investment Organized by Category of Investment

This appendix listed what utilities have pursued various SG investments. Appendix B contains an alphabetical listing of the various applications, technologies, and software investments contained in both this appendix and all the remaining appendices.

There are three main divisions being used to organize this information. These are:

I. Customer Information and Energy Management
II. Transmission & Distribution Control, Measurement, Monitoring
III. Communications and Supporting Systems

The list that follows is conservative. It reflects the minimum number of utilities pursuing a given SG-related investment. It is conservative for several reasons:

1. When grouping utilities under a particular investment, AMI for example, only those utilities that clearly identified AMI were included.
2. Some applications, automated distribution for example, are groupings of a variety of specific SG-related investments. Given time limitations, staff wasn't able to work to decipher exactly what specific investments were made by a given utility. Therefore, there are very likely more SG-related investments in the category titled automated distribution than are reflected in this list.
3. It is very likely that communications equipment and enterprise back office systems need at least some modernization in support of other SG-related investments. For example, AMI likely requires a variety of specific IT investments. If communications equipment and enterprise back office systems investments were not identified, they do not appear in this list.

I. Customer Information and Energy Management

a. Automated Metering Infrastructure (AMI)

Alabama Power
Arizona, Southwest Transmission Cooperative
Austin Energy
Black Hills/Colorado Electric Utility Co., Colorado

Burbank Water and Power
CenterPoint Energy, Houston Texas
Cheyenne Light, Fuel and Power Company
City of Fulton, Missouri
City of Fort Collins
City of Glendale Water and Power, California
City of Wadsworth, Ohio
City of Westerville, Ohio
Cleco Power LLC, Louisiana
Cobb Electric Membership Corp, Georgia
Commonwealth Edison
Connecticut Municipal Electric Energy Cooperative
Consolidated Edison Company of New York Inc.
Cuming County Public Power District, Nebraska
Delmarva Power
Denton County Electric Cooperative d/b/a CoServ Electric
Detroit Edison Company
Entergy New Orleans, Inc.
FirstEnergy Service Company, Ohio
Florida Power & Light Company
Georgia Power
Golden Spread Electric Cooperative, Inc., Texas
Idaho Power Company
Indianapolis Power and Light Company
Knoxville Utilities Board
Lakeland Electric, Florida
Lafayette Consolidated Government, LA
Long Island Power Authority (LIPA)
Madison Gas and Electric Company
Marblehead Municipal Light Department, Mass.
Minnesota Power
Oklahoma Gas and Electric (OK)
Pacific Northwest Generating Cooperative, Oregon
PECO (PA)
Potomac Electric Power Company (DC)
Rappahannock Electric Cooperative (VA)
Southern California Edison Company
Salt River Project Agricultural Improvement, Arizona
Sioux Valley Southwestern Electric Cooperative
Stanton County Public Power District, Nebraska
Talquin Electric Cooperative, Florida
Vermont Transco, LLC

b. <u>*Customer Display Device or Portal*</u>

i. Home Area Networks (HAN) (including Building Energy Management Systems (BEMS) for commercial and industrial applications)

AEP Ohio
City of Naperville, IL
Consolidated Edison Company of New York Inc.
Connecticut Municipal Electric Energy Cooperative
Entergy New Orleans, Inc.
NSTAR Electric & Gas Corporation (MA)
Oklahoma Gas and Electric (OK)
Reliant Energy Retail Services, Texas
Vermont Transco, LLC

ii. Web-based information portals

Connecticut Municipal Electric Energy Cooperative
Iowa Association of Municipal Utilities
NSTAR Electric & Gas Corporation (MA)
Reliant Energy Retail Services, Texas
Salt River Project Agricultural Improvement, Arizona
Vermont Transco, LLC

c. Meter Data Management System (MDMS)

City of Glendale Water and Power, California
Cleco Power LLC, Louisiana
Nevada, NV Energy, Inc.
Rappahannock Electric Cooperative (VA)
Vermont Transco, LLC

d. <u>*Automated Appliance*</u>

Lafayette Consolidated Government, LA
Reliant Energy Retail Services, Texas
Southern California Edison Company

a. <u>*Advanced Demand Response Management System (DRMS)*</u> and <u>*Direct Load Control Devices (includes smart appliances)*</u>

City of Anaheim
City of Fort Collins
Los Angeles Department of Water and Power
Nevada, NV Energy, Inc.
Atlantic City Electric Company
City of Naperville, IL
Cobb Electric Membership Corp, Georgia
Detroit Edison Company
Iowa Association of Municipal Utilities

Marblehead Municipal Light Department, Mass.
NSTAR Electric & Gas Corporation (MA)
Pacific Northwest Generating Cooperative, Oregon

II.Transmission & Distribution Control, Measurement, Monitoring

b. *Advanced Analysis/Visualization Software, Automated Capacitors,*
Long Island Power Authority (LIPA)

c. *Automated Distribution*
AEP Ohio
Arizona, Southwest Transmission Cooperative
CenterPoint Energy, Houston Texas
Central Lincoln People's Utility District (OR)
City of Leesburg, Florida
City of Naperville, IL
Florida Power & Light Company
Lafayette Consolidated Government, LA
Long Island Power Authority (LIPA)
Los Angeles Department of Water and Power
Oklahoma Gas and Electric (OK)
Minnesota Power
Pacific Northwest Generating Cooperative, Oregon
Progress Energy, (NC & SC)
Potomac Electric Power Company (DC)
Rappahannock Electric Cooperative (VA)
Southern California Edison Company

d. *Distribution Line Automation Equipment (DLAE)*
American Electric Power (AEP)
Atlantic City Electric Company
City of Tallahassee (FL)
City of Wadsworth (OH)
Commonwealth Edison (ComEd)
Consolidated Edison Company, (NY)
Detroit Edison (MI)
El Paso Electric (TX)
Hawaii Electric Company (HI)
Madison Gas
Snohomish PUD (WA)
Systems Project (WI)

e. *Distribution Management System Integration*
AEP Ohio
City of Leesburg, Florida

f. *Integrated volt-VAR control help provide the distribution grid with constant voltage levels*.

AEP Ohio
Detroit Edison (MI)
Progress Energy, (NC & SC)
Rappahannock Electric Cooperative (VA)
Southern California Edison Company
Vermont Transco, LLC

g. *Micro-processor based relays*
Arizona, Southwest Transmission Cooperative

h. *Phasor Data Concentrators (PDC or PDCs), Phasor Measurement Units (PMU or PMUs), and/or Transmission Synchrophasors*

American Transmission Company Transmission Systems Project I, (WI)
Duke Energy Carolinas, LLC
Entergy Services, Inc, Louisiana
Florida Power & Light Company
Idaho Power
Midwest Independent Transmission System Operator (IN),
Midwest Independent Transmission System Operator
New York Independent System Operator, Inc.
Pennsylvania, PJM Interconnection, LLC
Utah, Western Electricity Coordinating Council (WECC)

i. *Power Factor Management System (metering, power factor correction)*
Southern Company Services, Inc., (FL, Georgia, MS Carolinas)
Wisconsin Power & Light (WI)

j. *Reclosers (may be included as part of distribution automation)*
City of Wadsworth (OH)
Memphis Light, Gas and Water Division
NSTAR Electric Company.

k. *SCADA Communications Network (SCADA)*
Hawaii Electric Company (HI)
Vermont Transco, LLC

l. *Substation Automation*
Avista Utilities (WA)
City of Naperville (IL)
City of Naperville, IL
Consolidated Edison Company, (NY)
Kansas City Power & Light
Long Island Power Authority (LIPA)
Madison Gas and (WI)

Northern Virginia Electric Cooperative (VA)
PECO (PA)
PPL Electric Utilities Corporation (PA)
Progress Energy, (NC & SC)
Sacramento Municipal Utility District
Snohomish PUD (WA)
Southern Company Services, Inc., (FL, Georgia, MS Carolinas)

II. Communications and Supporting Systems

Communications between all digital devices and equipment to support T&D digital upgrades

AEP Ohio
American Transmission Company LLC, Wisconsin
Arizona, Southwest Transmission Cooperative
Atheros Smart Grid Project, Orlando Florida
Atlantic City Electric Company
Avista Utilities (WA).
Black Hills/Colorado Electric Utility Co., Colorado
Central Lincoln People's Utility District (OR)
City of Leesburg, Florida
Cleco Power LLC, Louisiana
Cobb Electric Membership Corp, Georgia
Connecticut Municipal Electric Energy Cooperative
Detroit Edison Company
Duke Energy Carolinas, LLC
Florida Power & Light Company
Hawaii Electric Company (HI)
ISO New England Massachusetts, etc.
Lafayette Consolidated Government, LA
Memphis Light, Gas and Water (TN)
Municipal Electric Authority of Georgia
Nevada, NV Energy, Inc
Northern Virginia Electric Cooperative (VA).
Oklahoma Gas and Electric (OK)
Powder River Energy Corporation (WY)
Salt River Project Agricultural Improvement, AZ
Southwest Transmission Cooperative (AZ)
Vermont Transco, LLC

Table One includes “any needed software and back office systems support.” While none is listed here, staff assumes that the investments listed in the Investment Inventory will require both new software and upgraded and/or new back-office systems.

Appendix B - Investment Glossary

There may be overlapping definitions in this list. One reason for this is variations in the terms used to describe similar or equal processes.

Advanced Analysis/Visualization Software
Systems installed to analyze grid information or help human operators.

Automated Appliance
Appliance that is able to receive, and automatically responds to, a signal (price or operating) from the utility or from an in-premises control system.

Automated Metering Infrastructure (AMI)
(AMI requires digital meters, 2-way communication, all the necessary computing hardware & software to generate bills, ability to send price & disconnect signals from utility to meters). It provides for two-way communication between the delivery infrastructure and the end consumer that enables real-time monitoring of individual nodes on the grid by the central office. It includes the smart meters, AMI server(s), Meter Data Management (MDM) system, required software, core AMI transport infrastructure and the required backhaul communications.

Automated Capacitors
Sensors that can monitor and control capacitor banks remotely in order to increase distribution efficiency.

Advanced Demand Response Management System (DRMS)
DRMS links the utility's back office to its customers. It is used to control distributed DR resources. From an enterprise systems point of view, the DRMS falls into a category of an information management system much like the Meter Data Management System and connects the flow of information to the DR devices to/from the utility.

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

controllers and other technologies to improve reliability and system performance, and optimizing system performance through voltage and VAR control to reduce losses, improve power quality.

Automated Distribution Feeders (ADF)
Implementing feeder automation that is virtually a simple extension of the substation automation by covering the feeders. ADF is usually implemented either based on a centralized approach or a distributed approach. Normally a distributed approach is simple and flexible. It can be implemented in a small scale but can only provide limited ADF functions. Instead, a centralized approach is capable of providing complete ADF functions but requires large scale implementation. Distribution Feeder Automation is the monitoring and control of devices located out on the feeders themselves: Line Reclosers, Load Break Switches, Sectionalizers, Capacitor Banks, and Line Regulators.

Automatic Feeder Switching
Automated Feeder Switching is the monitoring and control of electrically operable switches located outside the substation fence. Automated feeder switching usually involves remote control from a centralized location (I.e., control center). It is used to detect feeder faults, determine the fault location (between 2 switches), Isolate the faulted section of the feeder (between 2 feeder switches), and restore service to “healthy” portions of the feeder
Automated regulators Equipment involved in feeder automation may include Feeder level switches/reclosers with Intelligent Electronic Devices (IEDs), communications such as RF, cellular, WiMAX or fiber connection; communications server; software algorithms; communications surveys, field integration of communications, configuration, and integration and commissioning may also be provided.

Automation with Supervisory and Advisory Control
This refers to automation that includes both hardware and software. Power System Optimization Software or Supervisory Control allows the operator to apply objectives and constraints to achieve an optimal power system operation.

Automated Relays
These are relays that are better able to protect the system from the widespread effects of fast disturbances.

Communications between all digital devices on the distribution system including to feeders for AMI and distributed smart circuits
No single technology is optimal for all applications. Among the communications media now being used for AMI applications are cellular networks, licensed and unlicensed radio and power line communications. In addition to the media, the type of network is also an important part of communications design. Networks used for Smart Grid applications include fixed wireless, mesh networks, and a

combination of the two, fiber optics, Optical Ground Wire Cables, Microwave, Remote Radio Monitoring, Wi-Fi, and Internet networks are also under investigation. Communication architectures remain diverse for integrating residential devices with the grid. Approaches used include using the meter as a gateway to the home, Internet or other communication channels, radio frequency (RF) networks communicating in both licensed and unlicensed radio bands, mesh networks incorporate multi-hop technology where each node in the network can communicate with any other node, star networks utilize a central tower that can communicate with a large number of end devices over a wide area, and power line carrier networks.

Communications Infrastructure to support transmission lines and substations
The substation of the future will require a wide-area network interface to receive and respond to data from an extensive array of transmission line sensors, dynamic-thermal circuit ratings, and strategically placed phasor measurement units. The smart substation must be able to integrate variable power flows from renewable energy systems in real time, and maintain a historical record or have access to a historical record of equipment performance. Combined with real-time monitoring of equipment, the smart substation will facilitate reliability-centered and predictive maintenance. Some of the various applications include: Core Substation Infrastructure for IT; Communications Infrastructure to Support Transmission Lines & Substations;

Controllable/Regulating Inverters
Inverters that can be coordinated or managed collectively to provide grid support.

Continuity Grid Sensors
Helps enable communication with the central distribution points to improve outage detection.

Customer Display Device or Portal
Devices or portals through which energy and related information can be communicated to and from utilities or third party energy service providers.

Data Management
Data management covers all aspects of collecting, analyzing, storing, and providing data to users and applications, including the issues of data identification, validation, accuracy, updating, time-tagging, consistency, etc.

Direct Load Control Devices
A radio-controlled device on an appliance that allows the utility to directly control its use.

Distribution Line Automation Equipment (DLAE)
DLAE refers to one or more technologies involved in automating at least some part of distribution line operations. Technologies may include at least some of

the following: (1) remote sensing and reporting line switch position; (2) video monitoring to visually confirm line switch position; and/or (3) remote actuate/toggle line switches.

Distribution Management System Integration
Technologies may include at least some of the following: (1) remote sensing and reporting line switch position; (2) video monitoring to visually confirm line switch position; and/or (3) remote actuate/toggle line switches. One definition of distribution automation is "A set of intelligent sensors, processors, and communication technologies that enables an electric utility to remotely monitor and coordinate its distribution assets, and operate these assets in an optimal manner with or without manual intervention.

Enterprise Front and Back-Office Systems and their Integration
These are primarily IT-based systems that may include managing utility operations, demand response, connection to customer systems, power usage recording, customer billing.

Enterprise-wide view of system via intelligent one-line diagram
Electrical power system analysis software that simulates a wide range of backup, control, and other scenarios.

EVSE (EV chargers)
A Level I or Level II component that is used charge an electric car.

FACTS devices and HVDC terminals
Flexible AC transmission (FACTS) devices can be used for power flow control, loop flow control, load sharing among parallel corridors, voltage regulation, enhancement of transient stability, and mitigation of system oscillations. FACTS devices include the thyristor controlled series capacitor (TCSC), thyristor controlled phase angle regulator (TCPAR), static condenser (STATCON), and the unified power flow controller (UPFC).

Fault Current Limiter
A fault current limiter is a device that uses superconductors to instantaneously limit or reduce unanticipated electrical surges that may occur on utility distribution and transmission networks.

High Temperature Superconductor (HTS) Cable
These could be used for capacity or applications such as Very Low Impedance (VLI) to control impedance and power flow.

High Voltage Line Temperature and Weather Condition Sensors
Provide real-time temperature and weather conditions for to improve the efficiency of high voltage distribution lines and allow more accurate dispatch of

current in times of significant demand with reduced chance of outages due to line sag.

Home Area Networks (HAN) (including Building Energy Management Systems (BEMS) for commercial and industrial applications)

Whether a HAN or a BEMS it refers to a computer-based system that assists in managing energy use. It will be programmable and ideally has the ability to automatically respond to price signals in one or more ways.

Improved interfaces and decision support:

Improved interfaces and decision support will enable grid operators and managers to make more accurate and timely decisions at all levels of the grid, including the consumer level, while enabling more advanced operator training. Improved interfaces will better relay and display real-time data to facilitate: Data reduction; Visualization; Speed of comprehension; Decision support; System operator training.

Integrated volt-VAR control help provide the distribution grid with constant voltage levels.

Most enhanced voltage regulators also provide a means to monitor the line voltage

Intelligent Electronic Devices (IEDs)

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

Meter Data Management System (MDMS)

A meter data management system (MDMS) collects and translates meter data into information that can be used by the various utility applications such as billing, outage management, GIS and smart metering. The MDMS helps utilities meet the challenges of processing and managing large quantities of meter data.

Micro-processor based Protective Relays

These are substitutes for electromechanical and solid-state relays. They have benefits in performance (sensitivity and speed), reliability (security, selectivity, and dependability), availability, efficiency, economics, safety, compatibility, and capabilities of microprocessor multifunction protective relaying technology over the previous existing technologies.

Phasor Data Concentrators (PDC or PDCs)
A PDC forms a node in a system where phasor data from a number of PMUs or PDCs are correlated and fed out as a single stream to other applications

Phasor Measurement Units (PMU or PMUs)
These are high-speed sensors distributed throughout a network that can be used to monitor power quality and in some cases respond automatically to them.
Power Factor Management System (metering, power factor correction)
Power factor is the percentage of electricity that is being used to do useful work, and it is expressed as a ratio. The higher the ratio, the greater the efficiency. Power factor management involves advanced metering that more accurately measures true power factor. Automating 'power factor correction' is aimed at reducing costly energy loss which can help reduce overall system costs.

Power Quality Monitor
A device that monitors power quality within the distribution system.

Reclosers
Centrally monitor and report circuit status (i.e. either open or closed), centrally monitor and report actions performed on the recloser, Transmit commands to the recloser.

Redistribution Management System
Communication networking of distribution can provide *enhanced line voltage monitoring* (e.g., on-demand and scheduled voltage level reports, remote control of voltage level settings, and event-based reporting of regulator problems).

SCADA Communications Network (SCADA)
Supervisory Control and Data Acquisition generally refers to a system that collects data from various sensors at a factory, plant or in other remote locations and then sends this data to a central computer that then manages and controls the data.

Sensing and Measuring Technologies
Sensing and measurement technologies enhance power system measurements and information to evaluate the health of equipment, support advanced protective relaying, enable consumer choice and help relieve congestion. Examples include: Smart meters, Ubiquitous system operating parameters, Asset condition monitors, Wide-area monitoring systems (WAMS), Advanced system protection, Dynamic rating of transmission lines.

Smart Grid Maturity Model
One tool that may be helpful to the three utilities subject to UM1460, the Commissioners, and parties to this docket, is known as the Smart Grid Maturity Model (SGMM).[12] That model is actually a framework that is designed to help a utility self-assess its current smart grid status, prioritize its smart grid related actions, measure its smart grid progress, and assist in linking smart grid to other of the utility's planning efforts. San Diego Gas & Electric (S, D, and G&E) is one utility that has used this tool as part of its work developing its Smart Grid Plan which was recently submitted to the California Public Utilities Commission (CPUC).[13]

Software Applications
Software applications cover the programs, algorithms, calculations, data analysis, and other software that provides additional capabilities to distribution and transmission automation. These software applications can be in electronic equipment, in control center systems, in laptops, in handhelds, or in any other computer-based system.

Substation Automation
This involves a suite of hardware and software applications. For example, some of the technologies/functions involved include automatic supervision of interlocks, local and global alarms, detection fault location - useful for distribution systems, disturbance diagnostics, automation with supervisory and advisory control, complex logic for device protection and coordination, automatic generation of switching sequences, enterprise-wide view of system via intelligent one-line diagram, etc. Applications and data of interest may include remote access to IED/relay configuration ports, waveforms, event data, diagnostic information, video for security or equipment-status assessment, metering, switching, volt/VAR management, and others for maintaining uninterrupted power services to the end users

Substation Transformer Monitors
Number of substation transformers with monitoring devices that measure station transformer loading, operating temperature, oil condition, or parameters that affect capability.

Synchrophasors
Equipment that measures conditions on power lines — like power flows, voltage and some more exotic characteristics of electricity, like frequency and phase angle — and reports the information back to a computer at a grid control center.

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[12] *See:* Smart Grid Maturity Model, Software Engineering Institute, Carnegie Mellon University. http://www.sei.cmu.edu/smartgrid/tools/index.cfm,
[13] *See*: *Smart Grid Deployment Plan Application of San Diego Gas & Electric Company (U 902 E*), In the Matter of the Application of San Diego Gas & Electric Company (U 902 E) for Adoption of its Smart Grid Deployment Plan, Filed June 6, 2011.

Transmission Line Monitors
Number of monitoring devices that can measure transmission line loading, operating temperature, ground clearance, or other parameters that would affect capability.

Web-based information portals
A web-based site through which a customer is able to access information, such as, their own consumption and the price(s) they face.

Appendix C - Communications

Communications is such a significant part of SG that it became clear that it deserved its own chapter. With that said, it's quite challenging identifying a dividing line between communications and non-communications technologies. That difficulty underscores the degree to which SG technological investments are inextricably communications related.

Smart grid technologies and applications encompass a diverse array of modern communications, sensing, control, information, and energy technologies that are deployed to varying degrees by utilities across the U.S. and in other countries. The NSTC Report divides these technologies into three categories:

1. *Advanced information and communications technologies* (including sensors and automation capabilities) that improve the operation of transmission and distribution systems;
2. *Advanced metering solutions*, which improve on or replace legacy metering infrastructure; and,
3. *Technologies, devices, and services that access and leverage energy usage information*, such as smart appliances that can use energy data to turn on when energy is cheaper or renewable energy is available."[14]

Investments in these three categories all refer to information. If power grid modernization can be reduced to one word, that one word would be information. Power grid modernization is intended to update a power system that had less need for information since it "...was primarily radial, built for centralized generation, with few sensors, and dependent on manual restoration. Customers were faced with emergency decisions that were made over the phone link, there was limited price information and few customer choices were offered."[15] That

[14] Ibid, p. 1.
[15] V.K. Sood, Fellow, IEEE, D. Fischer, Senior Member, IEEE, J.M. Eklund, Member, IEEE, T. Brown,

paper raises the specter of a 'perfect storm'…that will require the "...next generation Smart Grid [to]...accommodate increased customer demands for improved power quality and energy efficiency. Higher fuel costs and regulation in respect of CO2 emissions and other environmental concerns will also have an impact on how the grid will be operated."[16]

Communications infrastructure represents a significant part of the electric grid modernization activities. Turning to a paper by Sood *et. al.,* they note that "Control systems will have to be modified and new operating procedures will need to be developed. This development will have to deal not only with the bi-directional power flows which may occur in what used to be essentially a radial distribution system, it must also accommodate the two-way data communication system required to manage all of these new applications and assets."[17] Kyle McNamara of Verizon proposes a utility's SG transformation can be broken down into three technical layers:

1. *"Power layer*—power generation, transmission, substations, distribution grid, and energy consumption;
2. *Communication layer*—local area network (LAN), wide area network (WAN), field area network (FAN)/AMI, and home area network (HAN), supporting IT infrastructure;
3. *Application layer*—demand response control, billing, outage control, load monitoring, real-time energy markets, and a new range of customer services." [18]

He makes the point that the communications layers "...provide seamless integration, real-time communication..." in order to manage the massive amounts

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CTO, WireIE *"Developing a Communication Infrastructure for the Smart Grid,"* p. 1, *See:* http://www.wireie.com/pdfs/Developing_a_Communication_Infrastructure_for_the_Smart_Grid.pdf
[16] Ibid.
[17] Ibid.
[18] Kyle McNamara, Verizon, *"Navigating the Road to Smart Grid: Modernizing the Critical Communication Infrastructure," See:* http://www.generatinginsights.com/whitepaper/navigating-the-road-to-smart-grid-modernizing-the-critical-communication-infrastructure.html

of information produced by greater power grid automation. That layer must support the utility's traditional power delivery role and also be flexible enough to respond to changes in the applications layer.

Communications investments represent a monumental shift in power grid complexity. Sood *et. al*. identifies seven capabilities, or features, that the communications infrastructure of the future power grid must provide, the communications system must:

1. Be secure;
2. Have the bandwidth to retrieve, cull, manage, store and integrate the large amounts of data that smart devices will produce;
3. Incorporate open standards and permit plug and play integrated approaches;
4. Cover the entire length and breadth of the Smart Grid to cover all aspects of generation, transmission, distribution and user networks;
5. Use all kinds of resources i.e. varying from hard-wired links to fiber optics, wireless, satellites and micro-wave links;
6. Evolve with the developing Smart Grid; and,
7. Cope concurrently with both legacy and next generation applications.[19]

High-speed and low-latency network to substations allows utilities to pursue fully *substation automatio*n operations. Video monitoring requires significantly more bandwidth. A field area network (FAN) allows mobile technicians access the utility's applications while in the field through always-on communications. Substation automation systems generally do not require much bandwidth but require always-on, low-latency connectivity in order to operate effectively. *Distribution SCADA* systems typically do not require much bandwidth and are latency tolerant but do require always-on connectivity in order to operate

[19] Ibid, p. 2.

effectively. Two-way network configured to communicate with line switches provides centralized control of these grid assets.

Communications to line switches does not require much bandwidth. If line switch operation is required for immediate disconnect or reconnect, they need always-on connectivity and low-latency communications across the distribution network.

Research indicates that central monitoring of remote transformers (monitoring includes voltages and currents, oil levels and temperatures) require very little bandwidth and are not latency dependent. Though, always-on connectivity is required.

Capacitor bank control (ability to switch bank in and out of operation along with monitoring and reporting) helps minimize voltage drops and also provide Volt /VAR Control (they switch in capacitor banks to compensate for VAR losses). Two-way communication networks can automate the process of switching in capacitor banks to maintain voltage levels and minimize VAR losses. From a communications perspective, capacitor banks do not require much bandwidth and are latency tolerant but benefit from always-on connectivity to enhance grid reliability.

Voltage regulators help provide the distribution grid with constant voltage levels. Most *enhanced voltage regulators* also provide a means to monitor the line voltage. A two-way communications network configured to provide always-on communication with remote voltage regulators provide utilities with the ability to centralize their monitoring and control. Communication networking of distribution can provide *enhanced line voltage monitoring* (e.g., on-demand and scheduled voltage level reports, remote control of voltage level settings, and event-based reporting of regulator problems). It is reported that the communications requirements for voltage regulators require little bandwidth and relatively latency tolerant. Though, always-on connectivity aids reliability.

Distribution networking can provide *enhanced Reclosure* functionality beyond what a normal recloser can achieve. This includes,

- Centrally monitor and report circuit status (i.e. either open or closed)
- Centrally monitor and report actions performed on the recloser
- Transmit commands to the recloser
- Centrally monitor and report statistics.

It is reported that Recloser communications does not require much bandwidth, though due to their role in restoring power, Reclosers need always-on connectivity and low-latency communications across the distribution network.

Communications Infrastructure Investments
(Note: The list of investments in this chapter is intended to represent investments in computing and information transmission technologies only. Considering how SG investments in other sections of this Report support communications, the technologies in this chapter represent a subset of technologies involved in communications for even greater power grid automation.)

A. **Fiber Optics**

1. *American Transmission Company LLC, Wisconsin* is building a fiber optics communications network for high-speed communications to maximize the full capability of phasor measurement networks across ATC's transmission system.

2. *Avista Utilities (WA)* is installing a. radio and fiber optic communications system that integrates real-time data from grid sensors with the grid operator's distribution management software platform.

3. *Memphis Light, Gas and Water (TN)* Division is installing an optic communications which integrates real-time data from grid monitors with the grid operator's distribution management software platform.

4. *Southwest Transmission Cooperative (AZ)* is upgrading the communications infrastructure of their transmission network by installing optical ground wire cables between several substations. The project also installs micro-processor-based protective relays and equipment monitors. Along with expansion of the communications network and power line carrier-based meter communications system.   SSVEC is expanding its existing fiber optic communication infrastructure and upgrading its monitoring software as well.

B. Microwave, Remote Radio Monitoring

Powder River Energy Corporation (WY) is installing distribution grid communications infrastructure throughout the entire service territory. Three sets of upgrades include: 1) new microwave terminals and antennas to the backhaul network between operators and the distribution grid, 2) upgrades that allow key substations to establish radio monitoring linkages with grid operators, and 3) new equipment that allows the computer platform for grid control to help integrate the communications upgrades.

C. Installing Wireless and other Technologies

*Oklahoma Gas and Electric (OK) i*s deploying a system-wide fully integrated **advanced metering system**, distribution of **in-home devices** to almost 6,000 customers, and installation of **advanced distribution automation systems**. The program implements **secure wireless** communications.

D. Insufficient Information to Determine the Technologies Involved

Duke Energy Carolinas, LLC
Upgrade communications infrastructure and technology at the corporate control center.

Central Lincoln People's Utility District (OR) is installing two-way communication between the utility and all of its 38,000 customers through a smart grid network and other in-home energy management tools. Deploy smart grid communication and control technology to optimize distribution system.

ISO New England Massachusetts, etc.
Communication infrastructure including advanced transmission software to determine real-time grid stability margins.

Municipal Electric Authority of Georgia is implementing information technology infrastructure to manage new automated or remotely controlled equipment deployed in the electric distribution system. The communication systems and automation equipment is being deployed within MEAG's distribution substations. The information technology infrastructure this project establishes will support future deployments of distribution automation and AMI by municipal utilities served by MEAG.

Appendix D - Transmission

In most cases, transmission automation involves installing a variety of communications equipment along with sensors, computing hardware and software. The categories below are an initial set of technologies and groupings. To some extent, which category a utility is listed in is somewhat arbitrary.

A. **<u>Phasor Data Concentrators (PDC or PDCs)</u>**

A PDC forms a node in a system where phasor data from a number of PMUs or PDCs are correlated and fed out as a single stream to other applications

Midwest Independent Transmission System Operator, Indiana
Project deploys PDCs

*New York Independent System Operator, Inc.*19 PDCs,

Pennsylvania, PJM Interconnection, LLC implements a data collection network, PDCs, communication systems, and advanced transmission software applications

Utah, Western Electricity Coordinating Council (WECC), deploys PDCs, communication systems, information technology infrastructure and advanced transmission software applications are being deployed in the project.

B. **<u>Phasor Measurement Units (PMU or PMUs)</u>**

These are high-speed sensors distributed throughout a network that can be used to monitor power quality and in some cases respond automatically to them. Phasors are representations of the waveforms of alternating current, which ideally in real-time, are identical everywhere on the network and conform to the most desirable shape. Advanced applications include enhanced forecasting of renewable generation and improved load and generation balancing.

American Transmission Company Transmission Systems Project I, Wisconsin
Install 3-5 PMU in geographically diverse sites in ATC's territory

Duke Energy Carolinas, LLC - Install 45 phasor measurement units in substations across the Carolinas

*Entergy Services, Inc, Louisiana*_ installation of 18 new phasor measurement units and training and educating grid operators and engineers on the use of phasor technology to improve critical decision making on grid operations.

Idaho Power is installing PMUs

New York Independent System Operator, Inc., to deploy 35 new PMUs,

Midwest Independent Transmission System Operator, Project deploys PMUs

Pennsylvania, PJM Interconnection, LLC, to deploy PMUs in 81 of its high-voltage substations

Utah, Western Electricity Coordinating Council (WECC) to deploy PMUs

C. **Synchrophasors**

Synchronized phasor measurements (synchrophasors) provide real-time measurement of electrical quantities from across a power system. Applications of synchrophasor measurements include system model validation, determining stability margins, maximizing stable system loading, islanding detection, system-wide disturbance recording, and visualization of dynamic system response. The basic system building blocks are GPS satellite-synchronized clocks, PMUs, PDCs, and visualization software. This equipment measures conditions on power lines — like power flows, voltage and some more exotic characteristics of electricity, like frequency and phase angle — and reports the information back to a computer at a grid control center.

SCADA[20] systems poll data from RTUs (remote terminal units) at relatively low rates, typically once every 2 to 4 seconds. Compared to RTUs, synchrophasors provide data at higher rates (up to 60 times per second) and with higher accuracy. Synchrophasors can also send real phase angles directly to SCADA, instead of having the system estimate the phase angles.

National Utility of Mexico, Commission Federal de Electricidad (CFE) has installed protection, automation, and control systems with synchrophasors to stabilize transmission lines (and lower voltage distribution lines) by tripping generation when the relays calculates the angular difference between the bus voltages every cycle.

[20] See the chapter on distribution for a discussion of SCADA.

Appendix E - Distribution

In most cases, distribution automation involves installing a variety of communications equipment along with sensors, computing hardware and software. The categories below are an initial set of technologies and groupings. To some extent, which category a utility is listed in is somewhat arbitrary.

A. ***Distribution Line Automation Equipment (DLAE)***

By DLAE, I'm referring to one or more technologies involved in automating at least some part of distribution line operations. Technologies may include at least some of the following: (1) remote sensing and reporting line switch position; (2) video monitoring to visually confirm line switch position; and/or (3) remote actuate/toggle line switches.

Snohomish PUD (WA) is installing DLAE on ten of 340 distribution circuits.

Atlantic City Electric Company is deploying 25,000 direct load control devices, intelligent grid sensors, automation technology, and communications infrastructure.

Detroit Edison (MI) is deploying distribution automation on 55 circuits and 11 substations upgraded with automated switches and monitor a voltage ampere reactive (VAR) control.

City of Tallahassee (FL) is upgrading their DMS to allow for interoperability between existing and new devices.

*El Paso Electric (TX) is i*nstalling a distribution automation to increase the monitoring and control of the distribution system and improve power restoration during emergencies.

B. ***Power Factor Management System***

Power factor is the percentage of electricity that is being used to do useful work, and it is expressed as a ratio. Power factor management involves advanced metering that more accurately measures true power factor. Automating 'power factor correction' is aimed at reducing costly energy loss which can help reduce overall system costs. Improving power factor can reduce costs by reducing the amount of energy required, lowering transmission and distribution losses, greater amount of capacity available to serve actual working power requirements, and reducing non-productive loading on the electrical system.

Wisconsin Power & Light (WI) is implementing a power factor management system to minimize overload on distribution lines, transformers and feeder segments, reduce distribution waste, and limit unnecessary power generation.

Southern Company Services, Inc., (FL, Georgia, MS Carolinas) is installing integrated upgrades of the distribution, transmission, and grid management systems throughout their large service territory. Major efforts include automation of major parts of the distribution system, automation of selected transmission lines, and new equipment for many substations.

C. ***Reclosers***

Conventional circuit breakers and fuses require a site visit to restore service interruption caused by the fault. A recloser can automatically attempt to close the circuit.

City of Wadsworth (OH) is upgrading and expanding its distribution automation equipment, including installation of automated reclosers (feeder switches) and capacitor.

Memphis Light, Gas and Water Division implements new intelligent relays and sensor equipment to provide remote switching at the transformer level and information to aid in system design, operation, and preventive maintenance.

NSTAR Electric Company will install new switches, monitors, and reclosers on selected circuits.

D. ***Remote Fault Indicators***

A fault indicator is a device which provides visual or remote indication of a fault on the electric power system. Also called a faulted circuit indicator (FCI), the device is used in electric power distribution networks as a means of automatically detecting and identifying faults to reduce outage time.

American Electric Power (AEP) uses a distribution automation controller (DAC) to automatically react to a fault and reconfigure the power delivery network using multifunction intelligent electronic devices (IEDs) connected to a communications network. Data are shared among power system-aware relays in the substations and advanced Reclosers on the pole top to make them aware of their surroundings and evolving situations. These IEDs also share data with the DAC, which then becomes aware of the entire distribution network and then observes system conditions and reacts by immediately sending commands to the IEDs to mitigate problems. The system detects and analyzes fault conditions, isolates the affected feeder section, and restores power to unaffected sections to reduce outage times effectively.

Commonwealth Edison (ComEd) applies Fault Indicators on Its Mesh Network to Improve Distribution Reliability. The fault indicator reduces ComEd's fault-finding time by communicating fault status back to a central location using an embedded radio. For the pilot project, ComEd distributed fault indicators throughout the utility's delivery area in northern Illinois. SCADA software processes the fault indicator information to make it compatible with ComEd's network. The new radio communications capability feature provides additional fault information sooner as part of the utility's smart grid efforts.

E. Supervisory Control and Data Acquisition (SCADA)

SCADA generally refers to the control system that monitors and controls utility infrastructure and a computer system for gathering and analyzing real time data. SCADA gathers information, transfers the information back to a central site, carries out analysis and control, and displays the information in a logical and organized fashion.

Hawaii Electric Company (HI) Eight of the company's 146 overall substations will receive new SCADA equipment and software. A new automated switch for a 46-kV sub-transmission line, along with a communication and monitoring system, integrates the new automated distribution equipment with the existing grid.

F. Smart Relays

According to Yi Zhang, conventional relays are not sophisticated enough to satisfy today's needs. In some situations, they are not adaptive enough to discriminate between fault and normal conditions, or to react correctly to faults. [21] He notes that conventional relays aren't able to discriminate between fault and normal conditions, or to react correctly to faults, and that a malfunctioning relay is among the most common modes of failure that accelerates the geographic spread (or the cascade) of faults.[22] He further notes that "…the trend in power system planning that utilizes tight operating margins with less redundancy, addition of distributed generators, and independent power producers, makes the power system more complex to operate and to control and, therefore, more vulnerable to disturbances. Current control strategies are sometimes inadequate to stop the spreading of disturbances. In such cases, one could only rely on protective relays to protect the system from the widespread effects of fast disturbances. This suggests that the protection systems should be more reliable, secure, and robust. Therefore, more intelligent and sophisticated protective relays are needed."[23]

City of Naperville (IL) is expanding their distribution automation capabilities, which include circuit switches, remote fault indicators, and smart relays.

G. ***Substation Automation***

(Note that investments that aid in substation automation appear under various technologies in this chapter.)

Some of the goals of substation automation include minimizing outages, reducing operating and maintenance costs, improve information management and productivity, and improved asset management. Substation automation involves a menu of hardware and software technologies to aid in power flow monitoring and control. For example, some of the technologies/functions involved include automatic supervision of interlocks, local and global alarms, detection fault location - useful for distribution systems, disturbance

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[21] Yi Zhang, "*Mitigating Future Blackouts via Smart Relays: A Machine Learning Approach,*" Submitted in partial fulfillment of the requirements for the degree of Doctor of Philosophy in Department of Electrical and Computer Engineering, Carnegie Mellon University, July, 2010, pg. 2.
[22] Ibid.
[23] Ibid.

diagnostics, automation with supervisory and advisory control, complex logic for device protection and coordination, automatic generation of switching sequences, enterprise-wide view of system via intelligent one-line diagram, etc.

Avista Utilities (WA) is automating the management of the distribution grid and installing a rapid communications and monitoring infrastructure. New switches, capacitors, and sensors are being installed in substations and distribution circuits across the project area.

Consolidated Edison Company, (NY) The project is deploying various types of distribution automation equipment, such as, substation and feeder monitors, automated switches, and capacitor automation devices on 850 feeder lines to improve operational efficiency and control.

Madison Gas and Electric Integrated and Crosscutting Systems Project (WI) is installing advanced distribution system at 5 substations and 14 associated feeders.

Northern Virginia Electric Cooperative (VA) is deploying digital devices to expand automation and control systems to cover a majority of their substations and distribution circuits. The project also deploys a new communications network to compliment the distribution system upgrades, providing more precise monitoring of grid operations.

PPL Electric Utilities Corporation (PA) is installing new automation equipment at 10 distribution substations and 50 distribution circuits.

Snohomish PUD (WA) is upgrading 42 of 85 substations with automated control capabilities to prepare the substations for full-scale deployment of distribution automation and integration of distributed energy resources

Sacramento Municipal Utility District is partially deploying advanced distribution grid assets that equip SMUD's distribution circuits with automated control and operation capabilities.

H. ***Multiple Technologies***

This section includes utilities that are pursuing a host of technologies and applications. In most cases, these technologies and applications overlap with other technologies in this chapter and possibly with other technologies in other chapters. They appear in this section to avoid listing a given utility multiple times.

PECO (PA) is deploying **AMI** and **distribution automation technologies**. AMI supports **new electricity pricing program**s for customers and pilot programs, such as in-home devices that provide energy information and energy usage control.

Progress Energy, (NC & SC) is installing a **distribution management system, automated switching, and integrated voltage and reactive power contro**l to reduce line losses and improve service reliability. The project involves installation of **advanced transmission systems including on-line monitoring equipment** on key and "at-risk" transmission substations and transformer banks.

Nevada, NV Energy, Inc., is deploying **communications infrastructure for all residential and commercial customers** and **pilot programs for time-based pricing options**, advanced customer service options, and electric vehicle monitoring. They are installing a **new meter data management system** (MDMS) that integrates all the smart meter data for use in system management, operations, and billing activities; an **advanced demand response management system** (DRMS) that integrates the utility's portfolio of demand response programs and provides a link to customer service, control operations, system operations, and other functions; and an **energy management system** links the control of the electric transmission, distribution, and generation facilities with the two distinct northern and southern Nevada balancing areas.

Potomac Electric Power Company (DC) is **installing 280,000 smart meters** equipped with the network interface, **institute dynamic pricing programs**, and deploy **distribution automation** and communication infrastructure technology to reduce peak load demand and improve grid efficiency. In the Maryland service area, **install 570,000 smart meters** with network interface; institute dynamic pricing programs, and deploy distribution automation and communication infrastructure technology to enhance grid operations.

Rappahannock Electric Cooperative (VA) is deploying **smart meters**, **distribution system infrastructure** and a **communications network to support the new smart grid** assets. As part of this project, REC is deploying smart meters throughout its service territory. Full coverage allows REC to introduce and **test advanced pricing programs and a pre-pay program**. The project includes a **MDMS** to assist in managing all the increased data available from the smart meters. The project also deploys **distribution automation** equipment including SCADA and automated controls on **distribution voltage regulators** to improve power quality, reduce line losses, and reduce operations and maintenance costs through monitoring and control of distribution voltage.

Vermont Transco, LLC (VT) deploys **AMI**, including approximately **300,000 smart meters** across the state over 3 years and provides **two-way communications** between customers and the utilities. The project includes **assessment of time-of-use and peak-time rebate pricing** programs through statistically rigorous consumer behavior studies that involve **consumer Web portals and in-home displa**ys. The project also involves **installation of automated voltage regulators** and **SCADA** equipment at selected substations, enabling better management of the distribution system and reducing operations and maintenance costs.

Appendix F - Customer

This section focuses primarily on capital investments at the end-user level in smart meters and various information systems behind the meter. It also includes some demand response and rates programs that rely on advanced metering technology. There are a number of utilities that are also installing various communications systems upstream of the customer's meter to support various investments at the customer level.

A. **Smart Meters**

Alabama Power
Alabama Power began installing smart meters throughout the city of Birmingham, with plans to continue the installation of 1.2 million smart meters to all of its customers throughout the state until 2011.

Austin Energy
Began installing smart meters in 2008. In October 2009, Oncor began its rollout of 3 million smart meters, to be completed by 2012.

Commonwealth Edison
Smart grid project includes deployment of 200,000 smart meters.

Georgia Power
They have installed smart meters for 400,000 utility customers, with plans to install additional smart meters throughout the state over the following three years.

Lakeland Electric, Florida
Install more than 125,000 smart meters network for residential, commercial and industrial electric customers across the utility's service area.

Talquin Electric Cooperative, Florida
Install a smart meter network system for 56,000 residential and commercial customers and integrate an outage management system.

B. Various Combinations of AMI System, Customer Information Access, Data Management Systems, Demand Response, Load Control Devices, and/or Time-Varying Rates

Atheros Smart Grid Project, Orlando Florida
The focus of the project is to modify existing power line communications to enhance smart grid functionality. (no other project information available

Black Hills/Colorado Electric Utility Co., Colorado
Install an additional 42,000 smart meters and communications infrastructure to help facilitate automated meter reading and provide a pilot for a dynamic pricing program in southeastern Colorado.

Burbank Water and Power
Deploy multiple integrated smart grid technologies, customer Smart Choice, Energy Demand Management programs, and enhanced grid security systems.

CenterPoint Energy, Houston Texas
Plans to complete the installation of 2.2 million smart meters (also install more than 550 sensors and automated switches).

Central Lincoln People's Utility District. Oregon
Provide two-way communication between the utility and its 38,000 customers through a smart grid network and in-home energy management tools. Deploy smart grid communication and control technology to optimize distribution system.

City of Anaheim
Upgrade and enhance the city's smart grid network and demand response systems, including installing 35,000 residential meters, as well as security and data systems.

City of Fort Collins
Install 79,000 smart meters and in-home demand response systems including in-home displays, smart thermostats and air conditioning and water heater control switches, automate transmission and distribution systems, and enhance grid security.

City of Glendale Water and Power, California
Install 84,000 smart meters and a meter control system that will provide customers access to data about their electricity usage and enable dynamic rate programs.

City of Leesburg, Florida
Develop a smart-grid energy management system. Deploy smart meter networks, energy management for municipal buildings, integrated distributed generation and new substation power transformer with enhanced monitoring and control. Key consumer initiatives include time differentiated rates and demand response options for reducing peak load.

City of Naperville, IL
City-wide deployment of AMI and an (expansion of distribution automation capabilities, which include circuit switches, remote fault indicators, and smart relays). Customers are allowed to purchase devices that assist in managing electricity use and costs, including in-home displays, programmable controllable thermostats, and direct load control devices for participation in load management programs.

City of Quincy, Florida
Smart-grid energy management system will deploy a smart grid network across the entire customer base, including two-way communication and dynamic pricing to reduce utility bills.

City of Ruston
The smart-grid energy management system will develop a fully functioning Smart Grid by improving customer systems, automating electricity distribution, and deploying a smart meter network and data management system.

Cleco Power LLC, Louisiana
Deploy smart meters, new metering communications infrastructure, and a meter data management system for all of Cleco's residential, commercial, and small industrial customers. The project implements two-way communications and utility applications.

Cobb Electric Membership Corp, Georgia
Install smart meters, enhanced communications infrastructure and make in-home displays and direct load control devices available. Implement two-way communications and utility applications to support customer Web portal and in-home displays.

Connecticut Municipal Electric Energy Cooperative
Deploy about 22,000 smart meters and advanced metering infrastructure AMI communication networks to: (1) allow customers to view their energy consumption at their convenience through an energy Web portal and/or an in-home display, and (2) allow the participating utilities to manage, measure, and verify targeted demand reductions during peak periods.

Delmarva Power
In December 2008, they received approval from the PSC to install smart meters at more than 300,000 homes. Integration began in fall 2009

Detroit Edison Company
AMI includes 600,000 smart meters and the customer systems include in-home displays, smart appliances, and programmable communicating thermostats. There is a dynamic pricing pilot program to assess demand response and customer acceptance.

Entergy New Orleans, Inc.
Install more than 11,000 residential smart meters and in-home display devices, coupled with dynamic pricing, to reduce energy use and electricity costs for low income families.

Florida Power & Light Company
Deploy AMI, new electricity pricing programs. AMI supports two-way communication between FPL and its consumers receiving smart meters. (Also, new distribution automation devices, synchrophasors, and line monitoring devices. distribution automation advanced monitoring equipment for the transmission system).

Hawaiian Electric
Install smart meters for 430,000 residential and commercial electric customers.

Idaho Power Company
AMI and customer systems to nearly all of Idaho Power Company's (IPC) residential and commercial customers. Enhanced billing and on-line energy monitoring systems provide detailed energy use information. Smart meters enable IPC to increase its offering of existing time-of-use rates. Peak load is also managed through direct load control devices on participating customers' irrigation systems.

Indianapolis Power and Light Company
Install more than 28,000 meters, including commercial, industrial and residential customers, provide energy use information to customers, improve service restoration and efficiency, and enable two-way communications and control capabilities for the grid.

Iowa Association of Municipal Utilities
IAMU, with 75 consumer-owned utilities, serving over 96,000 customers in 3 states, will implement a broad based load control and dynamic pricing program using smart thermostats and web based energy portals.

Lafayette Consolidated Government, LA
Install more than 57,000 smart meters to reach the full service territory with two-way communications, enable consumers to reduce energy use with smart appliances and dynamic pricing (also automate transmission & distribution systems).

M2M Communications, Boise
Install smart grid-compatible irrigation load control systems in California's central valley agricultural area in order to reduce peak electric demand in the state.

Marblehead Municipal Light Department, Mass.
Install an AMI system, a pilot dynamic pricing, and automated load management program. It also includes a study of consumer behavior in response to a critical peak pricing (CPP) service option.

Minnesota Power
Install AMI and explores the application of distribution automation.

Pacific Northwest Generating Cooperative, Oregon
Implement a smart grid system, including more than 95,000 smart meters, substation equipment, and load management devices, that will integrate 15 electric cooperatives across 4 states using a central data collection software system hosted by the Pacific Northwest Generating Cooperative.

Reliant Energy Retail Services, Texas
Deploy in-home energy displays, smart appliances, and new rates and pricing programs to customers. Customers will access their energy usage patterns through a Web portal and individualized weekly usage emails.

Salt River Project Agricultural Improvement, Arizona
Install smart meters, supporting communication infrastructure, a two-way communications system with upgraded software, a Web portal and expansion of existing time-of-use rates.

South Kentucky Rural Electric Cooperative Corporation
Install smart meters, enhanced communications infrastructure, in-home displays, and direct load control devices.

South Mississippi Electric Power Association
Install 240,000 smart meters and smart grid infrastructure across a range of SMEPA's member cooperatives.

Tri State Electric Membership Corporation
Two-way communications and utility applications to: 1) enable customers to view their energy consumption through a Web portal, 2) provide time-based

rate programs to customers; 3) provide information and tools to improve outage management.

Other utilities that are doing similar improvements (to group above) - not an exhaustive list

Black Hills Power, Inc
Cheyenne Light, Fuel and Power Company
City of Fulton, Missouri
City of Wadsworth, Ohio
City of Westerville, Ohio
Cuming County Public Power District, Nebraska
Denton County Electric Cooperative d/b/a CoServ Electric
FirstEnergy Service Company, Ohio
Golden Spread Electric Cooperative, Inc., Texas
Knoxville Utilities Board
Madison Gas and Electric Company
Sioux Valley Southwestern Electric Cooperative
Stanton County Public Power District, Nebraska

Appendix G - Regional Demonstration

These projects involve investments in multiple technologies that cut across vertical segments of the electric power system, and that are applied across large regions that may or may not be contiguous with one utility's service area. Since they involve multiple technologies, they are summarized by utility rather than by technology.

AEP Ohio
The demonstration includes approximately **110,000 meters** and **70 distribution circuits**. AEP Ohio will implement Smart Grid technology over 58 13kV circuits from 10 distribution stations and 12 34.5kV circuits from six distribution stations. Included in this project is a **redistribution management system**, **integrated volt-VAR control**, **distribution automation**, **advanced meter infrastructure**, **home area networks**, **community energy storage**, sodium sulfur battery storage, and **renewable generation sources**. These technologies will be combined with **two-way consumer communication and information sharing**, **demand response**, **dynamic pricing**, and consumer products, such as plug-in hybrid vehicles.

Austin Electric, Pecan Street Project Inc, Texas
Smart Grid systems that form the foundation of this project include **automated meter information**, **2-way meters**, **energy control gateways** (a home network system that links to a customer web portal), **advanced billing software**, and **smart thermostats**. These technologies will be integrated into a **micro grid** that links 1,000 residential meters, 75 commercial meters, and plug-in electric vehicles (PEV). At least 100 of the residential meters will have **rooftop solar photovoltaics** (PV), including 15 or more affordable residences. The project will also integrate 200 residences with **smart water and smart irrigation systems**. **Different storage technologies** will be tested including thermal storage, battery technologies (e.g., lithium-ion, lithium iron magnesium phosphate, metal air, and lead acid), and possibly ultra capacitors and fuel cell systems. **Distributed generation technologies** integrated into the Energy Internet include solar PV (crystalline silicon and thin film), **solar water heaters**, and **absorption chillers**. Through the use of Pecan Streets' two-way energy flow, customers can set electricity and water budgets, have software manage electricity use of individual appliances, and sell energy back to the grid; cars connected to the grid can be powered with solar energy and help level loads; and utilities can store power and deliver it when needed,

Battelle Memorial Institute
Collaborate with utilities, universities, and technology partners in a Smart Grid demonstration project across five states and three climatic regions, spanning the

electrical system from generation to end-use, and containing all key functionalities of the future Smart Grid. This demonstration will validate new technologies; provide two-way communication between distributed generation, storage and demand assets, and the existing grid infrastructure; quantify Smart Grid costs and benefits; advance interoperability standards and cyber security approaches; and validate new business models. A base of Smart Grid technology serving more than 60,000 customers will be installed, validated, and operated. All use classes are represented in the demonstration including residential, commercial, industrial, and irrigation customers.

Boeing Company, Missouri
Demonstrate the benefits of advanced Smart Grid technologies and concepts for **optimizing regional transmission system planning and operation** by **enabling wide-area situational awareness**, coordination, and collaboration in a secure manner. The project team includes the leading regional transmission organizations and utilities that serve all or part of 21 states and more than 90 million people. This project leverages network architecture and military-grade cyber security experience and capabilities that are scalable and enable interoperability with both legacy systems and new Smart Grid technologies. Team members will also develop public outreach and education programs to raise awareness of Smart Grid benefits.

CCET, TX (project is N of Houston)
Demonstrate approaches to **better manage wind reliability**, **improve wind generation capacity**, and enhance response through three Smart Grid applications: "Smart Meter Texas" control portal to **help match intermittent large-scale wind generation to load**; deployment of snychrophasor technology to improve grid reliability; and a state-of-the-art Smart Grid community with the latest high-efficiency construction, smart demand response appliances, energy storage, and distributed generation Smart Grid technologies.

Consolidated Edison Company of New York Inc.
Distributed storage, **AMI**, **home area networks**, **photovoltaics**, and **electric vehicle charging equipment** will be demonstrated. New technologies demonstrated include a **rules-based dashboard for control center operators**, a **risk management engine to facilitate efficient operation**, a **transmission decision management engine that aggregates electricity supply data**, an **adaptive stochastic controller, and an intelligent maintenance system**.

Kansas City Power & Light
Demonstrate an **end-to-end Smart Grid** —built around a **major Smart Substation** with a local distributed control system that includes **advanced**

generation, distribution, and customer technologies. Co-located **renewable energy sources**, such as solar and other parallel generation, will be placed in the demonstration area and will feed into the energy grid. Part of the demonstration area contains the Green Impact Zone, 150 inner-city blocks that suffers from high levels of unemployment, poverty, and crime.

Los Angeles Department of Water and Power
Collaborating with a consortium of research institutions to develop new Smart Grid technologies, quantify costs and benefits, validate new models, and create prototypes to be adapted nationally. The project consists of four broad initiatives including: **DR**; **EV Integration** into the LADWP Grid; **Customer Behavior**, **impact of Smart Grid communications systems and processes on customer usage**; energy savings from using Smart Grid enabled interfaces, **pricing options** and programs, and **effective messaging and incentives** regarding electric vehicles; and Next-Generation Cyber Security.

Long Island Power Authority (LIPA)
The demonstration project will integrate **AMI** technology with **automated substation and distribution systems**. AMI will be installed at 500 consumer locations, 250 will be residential. **Data collectors** will be installed along the corridor to facilitate network communications. LIPA will install digital **control and communications devices on 25 capacitor banks** and will also install devices that **automate monitoring and control of 18 underground feeders**. A key aspect of this project is to evaluate the impact of a range of variables on customer behavior and consumption, including **alternative tariff structures**, provision of **varying levels of information and analytical tools, and outreach** and energy automation for a sample of participating customers. Demonstration projects at the Farmingdale campus will include live residential and commercial models showing how intelligent devices can enable customers to understand and control their usage and integrate distributed renewable energy.

Massachusetts, NSTAR Electric & Gas Corporation
Enable residential dynamic pricing (time-of-use, critical peak rates, and rebates) and two-way direct load control by capturing **Automated Meter Reading** (AMR) data transmissions and communicating through existing customer-sited broadband connections in conjunction with home area networks. Record and transfer of interval consumption data to NSTAR via a **two-way communications** also used for sending load control signals, measuring demand response loads, and conducting event-specific impact evaluations. A second project will **enhance grid monitoring instrumentation** on one of its secondary area network grids in downtown Boston, MA.

New York Power Authority (NYPA)
Implement and demonstrate the effects that **Dynamic Thermal Circuit Ratings** (DTCR) technology can have on areas of the New York State transmission

system where there is the potential for wind generation. NYPA will use **real-time thermal ratings measurements** to correlate increased wind generation and increased transmission capacity. DTCR will be applied to three 230 kV transmission lines.

National Rural Electric Cooperative Association (VA)
NRECA will conduct studies in volt/volt-ampere reactive for total demand; **G&T demand response over AMI**; **critical peak pricing**; **water heater and air conditioning load control** over AMI; **advanced water heater control and thermal storage**; consumer **Internet energy usage portal pilots**; consumer **in-home energy display** pilots; **time-sensitive rates** pilots; distribution co-op **meter data management system applications**; and **self-healing feeders** for improved reliability.

NSTAR Electric & Gas Corporation (MA)
Enable **residential dynamic pricing** (time-of-use, critical peak rates, and rebates) and **two-way direct load control** by capturing Automated Meter Reading (**AMR**) data transmissions and communicating through existing customer-sited broadband connections in conjunction with home area networks. Record and transfer of interval consumption data to NSTAR via a two-way communications also used for sending load control signals, measuring demand response loads, and conducting event-specific impact evaluations. Customers will be able to view their **real-time energy consumption and costs through in-home displays and via a web portal**. A second project will **enhance grid monitoring instrumentation** on one of its secondary area network grids in downtown Boston, MA.

Oncor Electric Delivery Company, Texas
Oncor **will install and commission DLR technology at 26 locations distributed along eight transmission circuits**. These circuits have been identified as significantly constrained by the Electric Reliability Council of Texas. At each location sensors will be attached to transmission towers. **Radio receivers** will be installed inside ten substations. The remaining **dynamic line rating components** will be housed at a transmission management system control center in Dallas.

Southern California Edison Company
The technology demonstrations will include three main areas: (1) Energy Smart Customer Devices such as **smart appliances**, **home scale energy storage**, and **photovoltaic (PV) solar systems** to achieve Zero Net Energy homes and Zero Grid Impact EV charging at work; (2) **Year 2020 Distribution System** including distribution automation with looped circuit topology, **advanced voltage/VAR control**, **advanced distribution equipment**, **smart metering**, **utility-scale storage**, and **dispatched renewable distributed generation**; and (3) a Secure Energy Network to demonstrate end-to-end management of a

complex high performance telecommunication system linking the CAISO to SCE's back office, field networks, and energy smart devices in the home. Other specific aspects of sub-projects include: distribution circuit constraint management, enhanced circuit efficiency and power quality, self-healing circuits, deep grid situational awareness, and end-to-end cyber security and interoperability.

Appendix H - Integrated and Cross-cutting Systems

These are project that contain a whole host of technologies. They are listed by utility to simplify the presentation. They may cover a region as the projects in Appendix G do, or they may be within one utility.

A. Arizona, Southwest Transmission Cooperative

SWTC is upgrading the **communications infrastructure** of their transmission network by **installing optical ground wire cables** between several substations. The project also installs **micro-processor-based protective relays** and **equipment monitors**. MEC is replacing thousands of existing meters in its service territory with **smart meters** and is **expanding the communications network** and **power line carrier-based meter communications system**. SSVEC is implementing **AMI** and **distribution automation**. SSVEC is **expanding** its existing **fiber optic communication** infrastructure and **upgrading its monitoring software**.

B. Guam Power Authority

Deploy 46,000 **smart meters** to all of the utility's customers, install **automation technologies on the distribution system**, and implement the infrastructure needed to support a **two-way** communication.

C. California

1. _Modesto Irrigation District_

   Install 4,000 **smart meters**, **enhance the electricity distribution system**, and developing improved customer service programs including **dynamic pricing**, **billing system modifications**, and **education** and **outreach** efforts.

2. _Sacramento Municipal Utility District_

   System-wide deployment of an **AMI** integrated with existing enterprise and information technology systems as well as a **partial deployment of advanced distribution grid assets** that equip SMUD’s distribution circuits with automated control and operation capabilities, customer systems that provide usage and cost information to customers.

D. Carolinas

1. _Progress Energy, North & South Carolina_

   Deploy **AMI** and **distribution automation systems**. The project implements **two-way communications** to: (1) allow customers to view their energy consumption through a Web portal, and (2) allow Progress Energy to manage, measure, and verify targeted demand reductions during peak periods. The project includes a distribution management system, **automated switching**, and **integrated voltage and reactive power control** to reduce line losses and improve service reliability. The project involves **installation of advanced transmission systems including on-line monitoring** equipment on key and “at-risk” transmission substations and transformer banks.

2. *<u>Southern Company Services, Inc., FL, Georgia, MS, Carolinas</u>*
   Integrated **upgrades of the distribution, transmission, and grid management systems**. Major efforts include **automation of major parts of the distribution system**, **selected transmission lines**, and **new equipment for many substations**. The project centers on deployment of new distribution technologies that intend to improve power factor at delivery.

E. Westar Energy, Inc., Kansas

Implement technologies to transition the community into a smart energy city, including deploying 48,000 **smart meters**, **advanced distribution automation equipment**, **smart grid management software**, and **web-based customer engagement tools**.

F. Massachusetts

1. *<u>Town of Danvers</u>*
   Deploy more than 12,000 **smart meters** for the full customer base, **upgrade cyber security systems**, and **automate outage management and other distribution operations** with the goal of achieving full interoperability between all of the various systems.

2. *<u>Vineyard Energy Project</u>*
   Deploy a range of smart grid technologies, including **smart appliances**, an interface for plug-in hybrid electric vehicles, and a **demand response program** to improve integration of solar and wind.

G. New Hampshire Electric Cooperative

Modernize the distribution and metering system by **deploying advanced meters** for all 75,000 members and installing a **wide area telecom network** consisting of **microwave and fiber links** throughout the service territory.

H. Nevada, NV Energy, Inc.,

Deploy **smart meters** and communications infrastructure for all residential and commercial customers and pilot programs for **time-based pricing options**, advanced customer service options, and electric vehicle monitoring. Install a **new meter data management system** (MDMS) that integrates all the smart meter data for use in system management, operations, and billing activities. An **advanced demand response management system** (DRMS) integrates the utility's portfolio of demand response programs and provides a link to customer service, control operations, system operations, and other functions. An **energy management system** links the control of the electric transmission, distribution, and generation facilities with the two distinct northern and southern Nevada balancing areas.

I. Oklahoma Gas and Electric

Investments include system-wide deployment of a fully integrated **AMI**, distribution of **in-home devices** to almost 6,000 customers, and installation of **advanced distribution automation systems**. The program **implements secure wireless communications** to: 1) allow smart meter customers to view their electricity consumption data via a personalized Web site (study participants are testing other visual displays), and 2) allow OG&E to manage, measure, and verify targeted demand reductions during peak periods. New systems capture meter information for billing and implement new customer pricing programs and service offerings. The project deploys a more **dynamic distribution management system**, **automated switching**, and **integrated voltage and reactive power control**. The program also includes a study of consumer behavior in response to **different forms of dynamic pricing and home area network smart technology** on an opt-in basis.

J. PECO, Pennsylvania

Deploy **AMI** and **distribution automation assets**. AMI supports new **electricity pricing programs** for customers and pilot programs, such as in-home devices that provide energy information and energy usage control. Distribution automation helps PECO improve service to customers and reduce energy loss by managing circuit voltages.

K. Vermont Transco, LLC

Deploys **AMI**, including approximately 300,000 smart meters across the state over 3 years and provides **two-way communications** between customers and the utilities. The project includes **assessment of time-of-use and peak-time rebate pricing programs** through statistically rigorous consumer behavior studies. The project also involves **installation of automated voltage regulators** and supervisory control and data acquisition (**SCADA**) equipment at selected substations, enabling better management of the distribution system and reducing operations and maintenance costs.

L. Virginia, Rappahannock Electric Cooperative

Deploy **smart meters**, **distribution system infrastructure** and a **communications network** to support the new smart grid assets. Full coverage allows REC to introduce and test advanced pricing programs and a pre-pay program. The project includes a **meter data management system** (MDMS) to assist in managing all the increased data available from the smart meters. The project also deploys **distribution automation** equipment including supervisory control and data acquisition (**SCADA**) and **automated controls on distribution voltage regulators**.

M. Washington, D.C. Potomac Electric Power Company

Install 280,000 **smart meters** equipped with the network interface, institute **dynamic pricing programs**, and deploy **distribution automation** and **communication infrastructure**.

Appendix I - Energy Storage Demonstration

1. *Flywheel System*

Amber Kinetics, Inc., Fremont CA.
Develop a flywheel system from sub-scale research prototype to full-scale mechanical flywheel battery and will conduct both a commercial-scale and a utility-scale demonstration.

Beacon Power, MA (Project in PA)
Design, build, and operate a flywheel energy storage frequency regulation plant at the Humboldt Industrial Park in Hazle Township, Pennsylvania. The plant will provide frequency regulation services to grid operator PJM Interconnection. Two hundred flywheels will be connected in parallel to provide 20 MW in capacity and can fully respond in less than 4 seconds.

2. *Battery Systems*

City of Painesville, Ohio
Demonstrate vanadium redox battery storage capacity at the 32 mega-watt, coal-fired Painesville Municipal Power (PMP) plant. When fully implemented the plant will operate at a constant 26 MW, 80 percent of rated capacity.

Duke Energy Business Services, NC
The energy storage system will be designed and constructed using fast response, advanced lead-acid batteries configured to provide 36 MW output capabilities with a storage capacity of 24 MWh.

Ktech Corp, NM (Project in CA)
Integrate EnerVault's Vault-20 battery energy storage system. The system will be deployed at an agricultural site in California's Central Valley to store the energy generated by PV solar and dispatch power to run an irrigation pump and inject energy back into the utility.

Premium Power, MA
Demonstrate a multi-hour, zinc bromide battery- based energy storage system (ESS) for load shifting, peak shaving, renewable system integration, and support for micro-grid operations. Two utilities will demonstrate this technology, National Grid and Sacramento Municipal Utility District (SMUD).

Primus Power Corporation, CA
Deploy a 25 MW/75 MWh EnergyFarm™ in the Modesto Irrigation District substation in California that consists of a series of EnergyPods™; a plug-and -play zinc-flow battery combined with off-the-shelf components and power

Public Service Company of New Mexico
Co-locate a 2.8 MWh advanced lead acid battery with a separately installed 500kW solar photovoltaic (PV) plant to create a dispatchable distributed generation resource. This hybrid resource will provide simultaneous voltage smoothing and peak shifting and switch between two configurations, end-of-feeder and beginning-of- feeder.
Seeo Inc, CA.
Demonstrate a large-scale prototype of a solid-state electrolyte lithium-ion rechargeable battery.

Southern California Edison Company
Tehachapi Wind Energy Storage project is evaluating the performance of an 8 MW, 4 hour (32 MWh) lithium-ion battery system to improve grid performance and integration with large-scale wind-powered electricity generation.

3. *Compressed Air Storage*

New York State Electric & Gas
Compressed air energy storage plant with a rated capacity of 150 WM using an existing 4.5 million cubic foot underground salt cavern in Reading, New York.

Pacific Gas & Electric Company
Validate the design, performance, and reliability of and, build an advanced, underground Compressed Air Energy Storage (CAES) plant in California,

SustainX Inc.
Develop and demonstrate a modular, market-ready energy storage system that uses compressed air as the storage medium.

Appendix J - Rate Experiments, Pilots, Programs, and Tariffs

There are at least 70 pricing pilots and experiments that have been completed or are in progress nationwide. This appendix represents a sample and overview of the more widely cited pilots that studied consumer electric usage behavior changes in response to a variety of pricing programs and tariffs. No attempt to draft a comprehensive list of all pilots and experiments was made.

This listing is not designed to be a thorough and detailed summary of any specific effort nor does it compare the efficacy of the various efforts. Furthermore, this appendix does not explore any potential bias related to customer participation selection or incentives and it does not address the issue of sustainability.

A. California

1. *Report on PG&E's Opt In CPP Experiment*[24]

   The report contains ex post and ex ante load impact estimates for PG&E's residential time-based pricing tariffs. In 2010, PG&E had three time-based tariffs in effect: (1) SmartRateTM1 is a dynamic rate that is an overlay on other available tariffs. SmartRate has a high price during the peak period on event days, referred to as Smart Days, and slightly lower prices at all other times during the summer. Prices vary by time of day only on Smart Days; (2) Rate E-7 is a two-period, static time-of-use (TOU) rate with a peak period from 12 PM to 6 PM. This rate is closed to new enrollment; and (3) Rate E-6 is a three-period TOU rate with a peak period from 1 PM to 7 PM in the summer and from 5 PM to 8 PM in the winter (when partial peak prices are in effect).

   The report contains ex post load impact estimates for the above rates. It also examines the incremental impact of enabling technology on SmartRate demand response for customers that are enrolled in both PG&E's SmartRate and SmartAC programs. Load impact estimates for the SmartAC program are contained in a separate report.

[24] This summary is based on the Executive Summary of a report by Stephen S. George, Josh L. Bode, Elizabeth Hartmann, 2010 Load Impact Evaluation of Pacific Gas and Electric Company's Time-Based Pricing Tariffs, Final Report, April 1, 2011.

PG&E began offering SmartRate to residential customers in the Bakersfield and greater Kern County area in May 2008. This region was the first in PG&E's service territory to receive SmartMeters. By the end of the 2008 program year, enrollment in the Kern County area exceeded 10,000 customers. At the start of the 2010 summer season, enrollment had grown to around 24,500 customers and was extremely stable over the summer. In light of the pending termination of SmartRate, PG&E stopped actively marketing the rate in 2010, although enrollment remained open to new customers.

Under SmartRate, there can be up to 15 event days during the summer season, which runs from May 1st through October 31st. Prices only vary by time of day on SmartDays, unless a customer's underlying rate is a time-of-use (TOU) rate. The peak period on SmartDays is from 2 PM to 7 PM and customers are notified that the next day will be a SmartDay by 3 PM on the preceding day. The SmartRate pricing structure is an overlay on top of PG&E's other tariff offerings. SmartRate pricing consists of an incremental charge that applies during the peak period on Smart Days and a per kilowatt-hour credit that applies for all other hours from June through September. For residential customers, the additional peak period charge on Smart Days is 60¢/kWh.

There were 13 event days in 2010. The average load reduction across the five hour event window provided by residential SmartRate customers on each event day was 0.26 kW, or 14.1%, which is similar in percentage terms to the 2009 impact estimate of 15%. The average percent reduction ranged from a low of 5.7%6 on June 29th, the first event of the summer, to a high of 22.8% on September 10th. The average load reduction per participant ranged from a low of 0.11 kW on the first event day to a high of 0.47 kW on PG&E's system peak day, August 24, 2010. On that day, SmartRate participants reduced electricity use by 21.3% across the 2 PM to 7 PM event period.

Aggregate reductions in peak demand on Smart Days ranged from a low of 2.6 MW on the first event day, June 29th, to a high of 11.5 MW on PG&E's system peak day, August 24, 2010. Aggregate load reduction for the summer averaged 6.5 MW per event.

Due to a notification problem, slightly less than half of all participants were notified on June 29th, which largely explains the low impact estimate for that day.

In addition to meeting the basic load impact protocol requirements, detailed analysis has been conducted to understand how load impacts vary across several factors, including: (1) Local capacity area; (2) CARE status; (3) Number of successful notifications; and (4) Central air conditioning saturation and temperature (Note: CARE stands for California Alternate Rates for Energy, and is a program through which enrolled, low income consumers receive lower rates than do non-CARE customers). The analysis also investigates several important policy questions, including: (1) Attrition rates and the pattern of attrition for SmartRate participants; (2) Persistence of load impacts across multiple years; (3) Whether bill protection affects customer load impacts; (4) Whether load impacts vary between structural winners and losers; and (5) The extent to which automated load response via thermostats or direct load control switches produce incremental impacts over and above what customers with central air conditioning (AC) provide on their own.

Key findings from this detailed analysis include, but are not limited to, the following:

- Consumers do not appear to increase energy use in response to the slightly lower prices afforded on non-event days, nor do demand reductions on Smart Days carry over to other weekdays.
- CARE customers in aggregate responded less to price signals than other customers. However, after controlling for variations in underlying characteristics, such as air conditioning ownership, event notification and other factors, percent reductions for CARE customers are not significantly different from those of non-CARE customers.
- Event notification is highly correlated with load reductions. Comparative statistics show that both the average and percentage load reduction roughly triple between customers who are successfully notified through one option and those that receive four successful notifications.
- Customers that are enrolled in both SmartRate and SmartAC provide significantly greater demand response than those who are on SmartRate alone.
- There is a very wide range of demand response across customers. 36% of customers provide no load reduction at all, although one quarter of these participants (9% overall) did not receive event notifications. On the other hand, more than one third of all customers provided impacts of 0.2 kW or greater and 9% of all customers provided load reductions exceeding 1 kW.
- Load reductions do not decline over the course of multiple day event periods. Indeed, demand response on the second day of a two or three-day event sequence is higher than on the first day. Response on the third day is about the same as on the first day.
- Results indicate that (1) average load reductions appear to persist over time for customers that have been on the program for multiple years; (2) There is evidence that first year bill protection mutes price signals to some extent (regression analysis indicates that average load impacts are roughly 25% less when customers are under first year bill protection than when they are not.); (3) Load impacts for customers on

a balanced payment plan are not statistically significantly different from those of customers who are not on such a plan.

- The vast majority of customers who sign up for SmartRate have stayed on the program. Attrition is quite low after adjusting for customer turnover that is unrelated to the program (e.g., account closures). The attrition rate is highest during the first two months a customer is on SmartRate. CARE customers have marginally higher drop-out rates than non-CARE customers, all other things being equal. Drop-out rates differ only marginally in months that have a large number of events compared with months in which fewer events were called. On the other hand, high bills are correlated with higher drop-out rates, although less so for CARE customers than for non-CARE customers (whose bills fluctuate much more due to the much steeper increasing block rate structure faced by non-CARE customers.
- Load reductions are greater during summer months than in the winter, both in absolute and percentage terms. The average peak period reduction across the year is 0.16 kW or roughly 11%. In summer, the average is 0.21 kW and 12.7%. Percentage impacts range from a low of roughly 6% to a high of approximately 14%. The 14% impact occurs in May, right after the higher summer rates go into effect.

B. Connecticut

The Connecticut Light and Power Company/ Plan-It Wise Pilot

Another full scale pilot taking advantage of smart meters and three types of dynamic pricing was recently carried out by Connecticut Light and Power (CL&P). The Plan-It Wise Energy Pilot was designed as both a smart metering and rate plan pilot before the further deployment of smart meters to the 1.2 million metered electric customers in the CL&P service territory.[25] Consumers who participated received a smart meter, along with an enabling technology such as a smart thermostat, energy orb or appliance smart switch. Residential customers enrolled in the Peak-Time Price (PTP) rate plan reduced peak demand by 23.3% if supplied with an efficiency enabling device, and 16.1% without such a device. Commercial and industrial (C&I) PTP customers reduced peak demand 7.2% with a device and 2.8% without. On average, Plan-it Wise residential participants saved $15.21 over the three-month pilot span, while C&I customers averaged $15.45 in savings.99 In an exit survey, 92% of the residential and 74% of the C&I participants said they would be open to further programs.[26]

[25] Connecticut Department of Public Utility Control's Docket No. 05-10-03RE01 Compliance Order No. 4, Results of CL&P Plan-It Wise Energy Pilot, available at http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWise/$File/Planit%20Wise%20Pilot%20Results.pdf.

[26] Ibid.

C. Colorado

CO regulates two IOUs – Xcel Energy (aka Public Service Company of Colorado or PSCo) and Black Hills. Both IOUs have pricing pilots.

1. *Xcel*

   They have around 1.5m or so customers. The Xcel run pricing pilot uses the AMI infrastructure (~23,000 smart meters) installed via its SmartGridCity project as a platform to test dynamic rates. It should be noted that Xcel began this project prior to the ARRA funds and, thus, this project was not ARRA funded.

   Within a pool of the ~4,500 of the 23,000 who have smart meters, Xcel will be testing TOU, CPP, PTR rates with varying levels of participation under each rate.
   Xcel will also be offering some participants in the pilot with "IHSDs" or In Home Smart Devices which is a suite package of technologies including a router, a display device of some type, a smart thermostat, and 2 smart plugs.

2. *Black Hills*

   This is a considerably smaller utility than Xcel with about 93,000 customers. It serves the rural Southeast portion of the state

   They will have very soon AMI rolled out to very nearly every customer in its service territory. This was ARRA funded, matching dollar for dollar.

   Black Hills also has a pricing pilot testing dynamic rates with a pool of 200 residential customers.

3. There are other projects in the state amongst the munis and some co-ops. FortZED via the City of Fort Collins is a notable project. (Attached is a report from the Gov's Smart Grid Task Force released in January – in the appendix of that report you will find a summary of other SG related activities in the state beyond the 2 IOUs).

D. District of Columbia

1. *PowerCentsDC*

   One interesting pilot was PowerCentsDC[27]. Several reasons make their pilot unique,
   a. It was conceived in part by the official consumer advocate organization for D.C.

[27] PowerCentsDC Program, Final Report, September 2010. *See:* http://www.powercentsdc.org/ESC 2010-09-08 PCDC Final Report - FINAL.pdf

b. It tested three different price structures and various information formats, and
c. Limited income customers were recruited to test their price responsiveness.

Three pricing plans were studied, Critical Peak Pricing (CPP), Critical Peak rebates (CPR), and Real-Time Pricing (HP for Hourly Pricing) that followed the wholesale electric price. Customers with limited income participated only in the CPR option. It should be noted that summer peak reduction under CPR for the low-income group was 11 percent while it was 13 percent for 'regular' income customers.[28] Among other conclusions, they note that CPP led to the greatest reductions in peak demand while CPR was the most popular option.[29] Regarding low-income participants, participation rates were higher than for the regular income group, and the low-income group's peak reduction was only slightly less than that for the regular group.[30]

Rule was enacted in June 2009 that authorizes electric companies to implement smart metering infrastructure, pursuant to the authority of the PSC.

E. Illinois

1. <u>Power Smart Pricing Program</u>

According to discussions with ICC staff, the current ComEd and Ameren Power Smart Pricing program (PSPP) were legislatively created and are optional rates open to anyone.[31] According to the company web-site for Ameren, the Power Smart Pricing program is an hourly pricing program for residential customers. In this case, the electricity prices are set a day ahead by the hourly wholesale electricity market run by the Midwest Independent System Operator (MISO).

Also according to ICC staff, the ComEd RTP uses DAP for advisory purposes but bills used the RTPs. The Ameren program started that way but reverted to using the day ahead prices for billing. ICC staff noted that Ameren now has about the same number of participants as ComEd despite having a customer base one third the size. Follow the link to learn more about Midwest ISO prices compared to flat rate prices.[32] [33]

[28] Ibid, p. 11.
[29] Ibid, p. 5.
[30] Ibid.
[31] The ICC will be opening a docket soon to review the programs and the net benefits they may or may not be creating for non-participants
[32] *See:* http://www.powersmartpricing.org/about-hourly-prices/

Some observations about the experience there and some aspects of rates are contained in a presentation made by Anthony Star, then the Director of Policy and Evaluation for CNT Energy,[34]

- Residential RTP has been available there since 2003 for ComEd customers and since 2007 for Ameren customers.
- Seven years of prices show that real-time electric prices led to total bill savings in the 10 –15% range over time in all years but 2005. In 2005, real-time prices ended up driving bills 6% higher when compared to the flat rate (and 1/3 of customers still saved money and 87% of participants chose to stay on the real-time price tariff for 2006).
- Electric price volatility tracks gas price volatility
- Capacity costs an increasing part of the equation

According to the T&D World column, a survey of 600 residential homes "Nearly 60% of residential energy consumers are willing to change their electricity-use patterns to save money, though many seek savings in return for signing on to a demand-response program." One study performed by Frost & Sullivan titled "U.S. Smart Grid Market – A Customer Perspective on Demand Side Management,"[35] In that study, they noted a significant percent of those surveyed (78 percent) said they would be interested in adjusting their power usage with a one-day notice of prices. A smaller fraction (60 percent) expressed an interest in allowing the utility to cycle their air-conditioner if that resulted in a lower utility bill.

F. New Jersey

1. *MyPower Pricing Pilot Program*[36]

Public Service Electric and Gas Company (PSE&G) offered a residential TOU/CPP pilot pricing program in New Jersey during 2006 and 2007. The PSE&G pilot had two programs, myPower Sense and myPower Connection.

myPower Sense educated participants about the TOU/CPP tariff and they were notified of a CPP event on a day-ahead basis. myPower Connection

[33] ICC staff has indicated that in May both ComEd and Ameren will be filing a variety of reports including four year program evaluations that will contain a significant amount of new information and will be the basis for a docketed proceeding to review the programs.

[34] Anthony Star, Director of Policy and Evaluation (he is now with the ICC), CNT Energy, "*Imagining Real Time Pricing For the Masses,*" December 17, 2009, Illinois Statewide Smart Grid Collaborative.

[35] This report is quite expensive. I've relied on a separate 15 slide presentation for these comments.

[36] IEE Whitepaper, pp. 17-18.

participants received a free programmable communicating thermostat (PCT) that received price signals from PSE&G and adjusted their air conditioning settings based on previously programmed set points on critical days.

There were 1,148 participants in the pilot program; 450 in the control group, 379 in myPower Sense, and 319 in myPower Connection. The TOU/CPP tariff consisted of a base rate of $0.09 per kWh. There were three adjustments to this base rate, (1) a night discount of $0.05 per kWh in both summers, (2) an on-peak adder of $0.08 per kWh and $0.15 per kWh respectively in the summers of 2006 and 2007, and (3) a critical peak adder for the summer months that resulted in a critical peak prices of $0.78 per kWh and $1.46 per kWh, respectively, in the summers of 2006 and 2007.

The results from this experiment were as follows,[37]

- myPower Sense customers with Central A/C reduced peak load
  - by three percent on TOU only days.
  - by 17 percent on peak days.
- myPower Sense customers without Central A/C reduced peak load
  - by six percent on TOU-only days, and
  - by 20 percent on CPP days.
- myPower Connection customers (those with the PCT) reduced their peak demand
  - by 21 percent due to TOU-only pricing
  - by 47 percent on CPP days

G. Ohio

S.B. 221 was enacted in May 2008. It required the state's primary utilities to file "electric security plans" with the state public utilities commission specifically related to smart grid and/or smart metering. Each utility's proposal included the installation of smart meters.

H. Maryland

Baltimore Gas & Electric Company (BGE)

BGE recently tested customer price responsiveness to different dynamic pricing options through a Smart Energy Pricing (SEP) pilot. The rates were tested in combination with two enabling technologies: an IHD known as the energy orb, a sphere that emits different colors to signal off-peak, peak, and

[37] Ibid, p. 18.

critical peak hours, and a switch for cycling central air conditioners. Without enabling technologies, the reduction in critical peak period usage ranged from 18 to 21%. When the energy orb was paired with dynamic prices, critical peak period load reduction impacts ranged from 23 to 27%. The ORB boosted DR approximately by 5%. BGE repeated the SEP pilot for the second time in the summer of 2009. Results revealed that the customers were persistent in their price responsiveness across the period. The average customer reduced peak demand by 23% due to dynamic prices only. When the ORB was paired with dynamic prices, the impact was 27%.[38]

I. Texas[39]

1. *Reliant Energy Retail Services*

2. The Public Utilities Commission of Texas (PUCT) staff wrote a report to the Texas legislature last year covering AMS deployment in Texas and efforts, to include DP pilots, outside the state. Among the points made are the following,

    - Demand response programs that rely on dynamic pricing or TOU rates are only just beginning to be offered in Texas. Currently, Nations Power offers prepaid service with RTP. This service is only available to customers with smart meters installed on their premises. The smart meters provide consumption data in fifteen minute intervals, enabling the company to provide customers RTP. Customers can see their historical and current consumption and current prices.

    - TXU Energy offers a TOU rate that encourages their residential customers to save money by shifting demand to off-peak hours. Under this plan, customers pay a higher peak rate during summer afternoons (1-6pm, M-F, May-October) when demand is highest and a lower rate at all other times of the year. The lower rate applies to 93% of the hours of the year.

    - Reliant Energy also offers a TOU plan that rewards the customer for shifting demand to lower priced off peak periods. Reliant's plan divides pricing periods into three categories, off peak, standard and summer peak. The higher summer peak hours account for only 3% of the total hours in the year (4-6pm, M-F, April-October). Standard pricing applies to the other periods of high demand and varies by season. Reliant's TOU plan is available to customers with smart meters.

[38] Faruqui, Ahmad, Sanem Sergichi, Effects of In-Home Displays on Energy Consumption: A Summary of Pilot Results, Peak Load Management Alliance Webinar, April 6, 2010.
[39] Comments are based on correspondence and phone calls with PUCT staff.

- Reliant is also piloting the implementation of in-home displays with consumers in Texas. This product offers consumers the ability to see real time consumption and projected bill amounts. In addition, Reliant Energy offers email alerts that utilize the 15-minute interval consumption data to provide weekly insights into consumption and projected bill amounts.

- Gateway Energy Services recently launched the Lifestyle Energy Plan, a three month pilot program to test two different TOU rates. Under the pilot, customers will continue to be billed on their current flat rate structure but will be able to see their monthly bill based on a TOU rate. Customers will have online access to reports detailing their usage and a side-by-side billing analysis of the TOU rate plan versus their flat rate plan. At the end of the pilot, customers who would have saved money with the TOU rate plan will receive a credit on their monthly bill equal to that savings. Criteria for customer participation included having a smart meter installed and enrollment in Gateway's variable rate plan.75

J. Multi-State

1. *Faruqui and Sergici Report*[40]

   The report by Faruqui and Sergici referenced in the above provides a survey of seventeen U.S. pricing experiments. The report provides an excellent, and concise, overview of a variety of pricing experiments in the U.S. and other countries. Those seventeen experiments used different pricing strategies (TOU and CPP), were conducted for varying lengths of time, with different number of participants, with and without enabling technology. The overarching conclusion is these pricing schemes can substantially reduce consumption at critical periods. People do respond to the price signals. Table 1 summarizes features of the experiments summarized in that report. Figure 1 illustrates the range of DR impacts from each of those experiments.[41] Notes for Table 1 follow that table.

[40] Rather than replicate their entire report here, you will find the details in their report. What is included here is a table summarizing the experiments studied and the percentage reduction in peak load of each experiment.

[41] Both Figure 1 and Table 1 are form the report summarized.

Table 1- Overview of the Experiments

Pilot	State	Utility	Year	Number of Customers	Number of Rates Tested in the Pilot
Anaheim Critical Peak Pricing Experiment	California	Anaheim Public Utilities (APU)	2005	52 control, 71 treatment	1
California Automated Demand Response System Pilot (ADRS)	California	Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)	2004-2005	In 2004: 104 control, 122 treatment In 2005: 101 control, 98 treatment	1
California Statewide Pricing Pilot (SPP)	California	Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)	2003-2004	2,500 customers	3
The Gulf Power Select Program	Florida	Gulf Power	2000-2001	2300 customers participating in the RSVP program	2
Electricite de France (EDF) Tempo Program	France	Electricite de France	Since 1996	400,000 customers	1
Idaho Residential Pilot Program	Idaho	Idaho Power Company	2005-2006	TOD Program- 420 control, 85 treatment EW Program- 355 control, 68 treatment	2
The Community Energy Cooperative's Energy-Smart Pricing Plan (ESPP)	Illinois	Community Energy Cooperative	2003-2005	1,500 customers	2
AmerenUE Residential TOU Pilot Study	Missouri	AmerenUE	2004-2005	TOU - 89 control, 88 treatment TOU/CPP- 89 control , 85 treatment TOU/CPP w/ Technology- 117 control, 77 treatment	2
GPU Pilot	New Jersey	GPU	1997	Not Available	2
Public Service Electric and Gas (PSE&G) Residential Pilot Program	New Jersey	Public Service Electric and Gas Company (PSE&G)	2006-2007	450 control, 836 treatment	1
Energy Australia's Network Tariff Reform	New South Wales	Energy Australia	2005	TOU program: 50,000 customers SPS: 1300 treatment	Tested several dynamic tariffs.
Ontario Energy Board Smart Price Pilot	Ontario/Canada	Hydro Ottawa	2006-2007	125 control, 373 treatment	3
Puget Sound Energy (PSE)'s TOU Program	Washington	Puget Sound Energy	2001-2002	300,000 customers	1
Olympic Peninsula Project	Washington and Oregon	Bonneville Power Administration, Clallam County PUD, The City of Port Angeles, Portland General Electric, and PacifiCorp	2005	28 control, 84 treatment	3
Xcel Experimental Residential Price Response Pilot Program	Denver- Colorado	Xcel Energy	2006-2007	1350 control, 2349 treatment	3

Notes:

*Percentage reduction in load is defined relative to different bases in different pilots. The following notes are intended to clarify these different c

1. TOU with Technology (TOU w/ Tech) and CPP with Technology (CPP w/ Tech) refer to the pricing programs that had some form of e

2. TOU program impacts are defined relative to the usage during peak hours unless otherwise noted.

3. CPP program impacts are defined relative to the usage during peak hours on CPP days unless otherwise noted.

4. Ontario- 1 refer to the percentage impacts during the critical hours that represent only 3-4 hours of the entire peak period on a CPI

   percentage impacts of the programs during the entire peak period on a CPP day.

5. TOU impact from the SPP is based on the CPP-F treatment effect for normal weekdays on which critical prices were not offered.

6. ADRS- 04 and ADRS- 05 refer respectively to the 2004 and 2005 impacts. ADRS impacts on non-event days are represented in the TO

7. CPP impact for Idaho is derived from the information provided in the reviewed study. Average of kW consumption per hour during th

   days) is approximately 2.5 kW for a control group customer while this value is 1.2 kW for a treatment group customer. Percentage imp

   calculated as 50%.

8. Gulf Power-1 refers to the impact during peak hours on non-CPP days and therefore shown in the TOU with Technology section whi

   impact during CPP hours on CPP days.

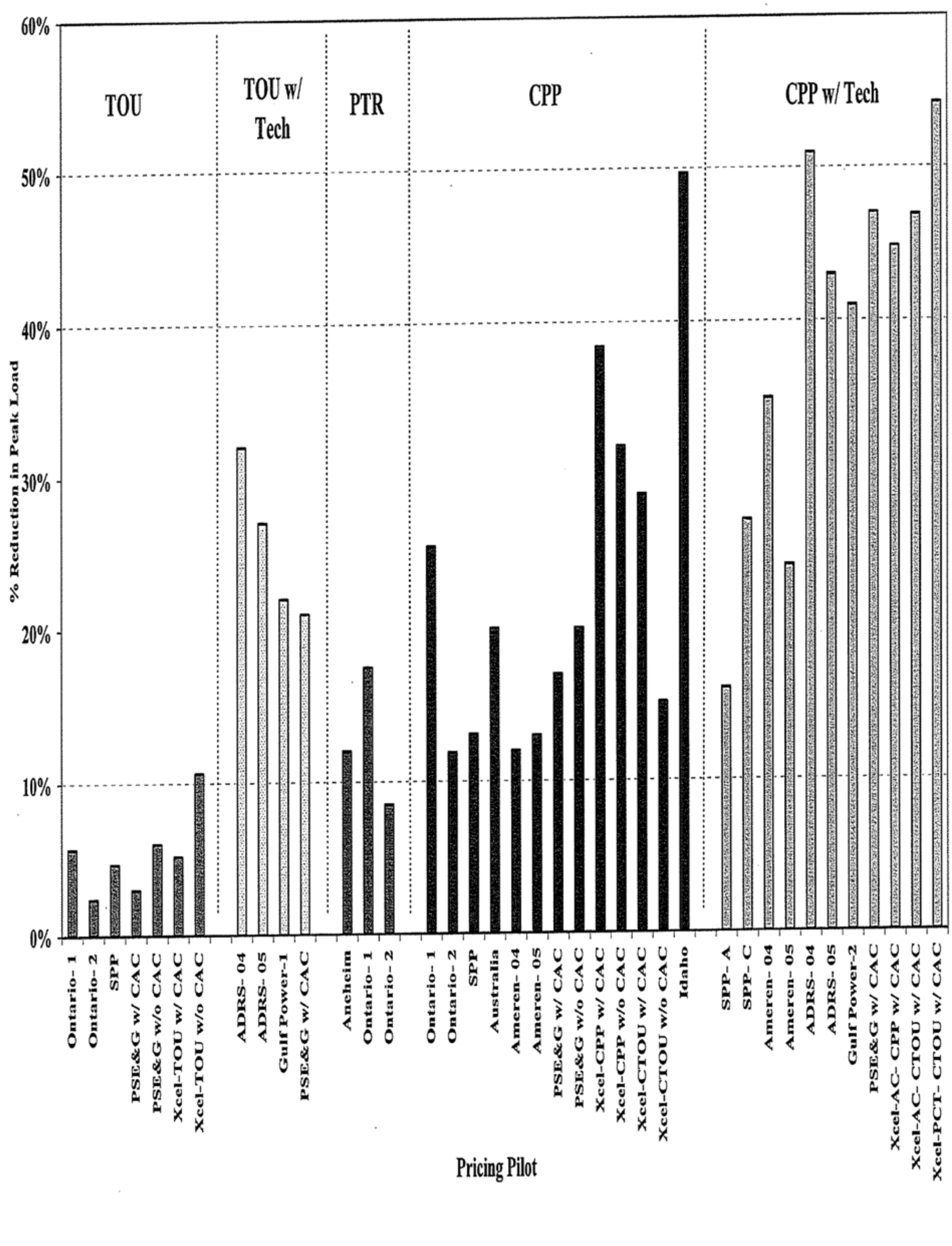
9. Ameren- 04 and Ameren- 05 refer to the impacts respectively from the summers of 2004 and 2005.

10. SPP- A refers to the impacts from the CPP-V program on Track A customers. Two thirds of Track A customers had some form of enab

11. SPP- C refers to the impacts from the CPP-V program on Track C customers. All Track C customers had smart thermostats.

12. Xcel-CPP program only differentiates between CPP and non-CPP hours while Xcel-CTOU program differentiates between CPP, on-pe

Figure 1- Estimated Demand Response Impact by Experiment



CERTIFICATE OF SERVICE

UM 1460

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 3rd day of October, 2011 at Salem, Oregon.

Kay Barnes

Kay Barnes
Public Utility Commission
Regulatory Operations
550 Capitol St NE Ste 215
Salem, Oregon 97301-2551
Telephone: (503) 378-5763

UM 1460
Service List (Parties)

***OREGON DEPARTMENT OF ENERGY**	
VIJAY A SATYAL SENIOR POLICY ANALYST	625 MARION ST NE SALEM OR 97301 vijay.a.satyal@state.or.us
***OREGON DEPARTMENT OF JUSTICE**	
JANET L PREWITT ASSISTANT AG	NATURAL RESOURCES SECTION 1162 COURT ST NE SALEM OR 97301-4096 janet.prewitt@doj.state.or.us
CITIZENS' UTILITY BOARD OF OREGON	
GORDON FEIGHNER ENERGY ANALYST	610 SW BROADWAY, STE 400 PORTLAND OR 97205 gordon@oregoncub.org
ROBERT JENKS EXECUTIVE DIRECTOR	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
G. CATRIONA MCCRACKEN LEGAL COUNSEL/STAFF ATTY	610 SW BROADWAY, STE 400 PORTLAND OR 97205 catriona@oregoncub.org
COMMUNITY ACTION PARTNERSHIP OF OREGON	
JESS KINCAID ENERGY PARTNERSHIP COORDINATOR	PO BOX 7964 SALEM OR 97301 jess@caporegon.org
ENERGY TRUST OF OREGON	
JOHN M VOLKMAN GENERAL COUNSEL	851 SW 6TH AVE SUITE 1200 PORTLAND OR 97204 john.volkman@energytrust.org
GRID NET	
JOHN COOPER	360 BRANNAN ST, STE 501 SAN FRANCISCO CA 94107 john@grid-net.com
IDAHO POWER COMPANY	
CHRISTA BEARRY	PO BOX 70 BOISE ID 83707-0070 cbearry@idahopower.com
JAN BRYANT	PO BOX 70 BOISE ID 83707-0070 jbryant@idahopower.com

LISA D NORDSTROM ATTORNEY	PO BOX 70 BOISE ID 83707-0070 lnordstrom@idahopower.com
MICHAEL YOUNGBLOOD MANAGER, RATE DESIGN	PO BOX 70 BOISE ID 83707 myoungblood@idahopower.com
MCDOWELL RACKNER & GIBSON PC ADAM LOWNEY	419 SW 11TH AVE, STE 400 PORTLAND OR 97205 adam@mcd-law.com
WENDY MCINDOO OFFICE MANAGER	419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 wendy@mcd-law.com
LISA F RACKNER ATTORNEY	419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 lisa@mcd-law.com
NW ENERGY COALITION WENDY GERLITZ SENIOR POLICY ASSOCIATE	1205 SE FLAVEL PORTLAND OR 97202 wendy@nwenergy.org
OREGON DEPARTMENT OF ENERGY DEANNA HENRY EMERGENCY PREPAREDNESS MANAGER	625 MARION ST NE SALEM OR 97301-3737 deanna.henry@state.or.us
PACIFIC POWER & LIGHT MICHELLE R MISHOE LEGAL COUNSEL	825 NE MULTNOMAH STE 1800 PORTLAND OR 97232 michelle.mishoe@pacificorp.com
PACIFICORP DOUG MARX	PO BOX 39 MIDVALE UT 84047 douglas.marx@pacificorp.com
PACIFICORP, DBA PACIFIC POWER OREGON DOCKETS	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PORTLAND GENERAL ELECTRIC	
DOUG KUNS RATES & REGULATORY AFFAIRS	121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com
PORTLAND GENERAL ELECTRIC COMPANY J RICHARD GEORGE	121 SW SALMON ST 1WTC1301 PORTLAND OR 97204 richard.george@pgn.com

PUBLIC UTILITY COMMISSION OF OREGON	
MAURY GALBRAITH	PO BOX 2148 SALEM OR 97308 maury.galbraith@state.or.us
PUC STAFF--DEPARTMENT OF JUSTICE	
MICHAEL T WEIRICH	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@doj.state.or.us
SMART GRID OREGON	
ROBERT FRISBEE	111 SW 5TH AVE, STE 120 PORTLAND OR 97204 rfrisbee@si-two.com
ROY HEMMINGWAY	111 SW 5TH AVE, STE 120 PORTLAND OR 97204 royhemmingway@aol.com
PHIL KEISLING	111 SW 5TH AVE, STE 120 PORTLAND OR 97204 pkeisling@gmail.com
SMART GRID OREGON/ECOTALITY COUNSEL	
BARRY T WOODS	5608 GRAND OAKS DR LAKE OSWEGO OR 97035 woods@sustainableattorney.com