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Report to the 82nd Texas Legislature

A Report on Advanced Metering as Required by House Bill 2129

Public Utility Commission of Texas
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Public Utility Commission of Texas

September 29, 2010

Honorable Members of the Eighty-second Texas Legislature:

We are pleased to submit our third Report on Advanced Metering as required by HB 2129. HB 2129, passed by the 79th Texas Legislature directed the Commission to report on the efforts of utilities in Texas to deploy advanced metering systems and infrastructure, and to identify any barriers to the implementation of advanced metering, and make any recommendations to address those barriers.

The Commission believes that the deployment of advanced metering is a critical component of the evolving Texas electric market and over time will help to balance the dynamics of supply and demand. As deployment occurs, it will enhance reliability and facilitate grid restoration, give customers more choice and control over their electric bill, enable market-based demand response, help the market to mature, yield savings for utilities, and create efficiencies in market processes for REPs and ERCOT.

Most importantly, AMI has the potential to provide enhancements in service to retail customers, and also give customers the tools to help manage energy costs.

We look forward to continuing to work with you on this and other issues relating to electric service. If you need additional information about any issues addressed in the report, please call on us.

Sincerely,

Barry T. Smitherman
Chairman

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Introduction

State legislation has encouraged the implementation of advanced metering (smart metering or AMS), by directing the Public Utility Commission to establish a cost recovery mechanism for utilities that deploy smart meters and related networks. In 2010, the transmission and distribution utilities (TDUs) in the ERCOT region began deploying smart meters at a significant scale, and they expect to have two million meters installed by the end of the year.

The installation of smart meters and the associated systems is a building block to achieving significant improvements in customer service and lower costs. To fully realize the benefits of AMS, retail electric providers (REPs) and customers will need access to information that shows how much electricity the customers use and when they use it. The smart meters record this information, and a web site funded by the largest of the investor-owned utilities in ERCOT is making this information available to REPs and customers. Already, utilities are able to carry out customers' service orders to initiate or terminate service or switch to a different REP very quickly for customers with smart meters. REPs are beginning to offer service plans with rates that vary by time of day, to reflect the price variations in the wholesale electricity market. Customers who elect such plans may be able to reduce their consumption in periods of high prices and thereby reduce their electricity costs.

Another benefit of smart meters is the ability of utilities to reduce outage times for customers when events occur that interrupt their electric service. The communications capability of smart meters gives utilities the ability to send a message to a meter and receive a response that indicates whether a customer has service at the home or business. Utilities are developing systems to incorporate this capability into their service restoration procedures. This capability should facilitate identifying the extent of an outage and planning the efficient restoration of service. The result will be quicker restoration of service in the case of equipment failures that result in loss of service for dozens of customers following a thunderstorm or equipment failure or loss of service for thousands of customers following a hurricane or tropical storm. Smart meters also automate meter-reading, reducing the cost of electric delivery service and will facilitate increased automation of the distribution system, so that restoring service after some outages will be achieved without dispatching a service crew.

Over 1.5 million smart meters have been installed by investor-owned utilities in Texas, but smart meters are not exclusively a Texas phenomenon. It is anticipated that by year end 2010, approximately 16 million smart meters will be in place in the U.S and 50 million by 2015. Legislation at the federal level has also addressed modernizing electricity infrastructure. The Energy Independence and Security Act of 2007 adopted a policy to "to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet the future demand growth." One of the key benefits envisioned from smart meters is that by giving customers better information about their consumption and retail rates that reflect wholesale costs, customer demand will be reduced, as customers become more efficient in their use of electricity and shift consumption to lower-cost hours, thus reducing the need for investment in new peak capacity.

In response to the statutory directive to identify changes to Texas policy necessary to remove barriers to the use of advanced metering and metering information networks or other advanced transmission and distribution technologies, the Commission offers the following recommendation for consideration by the Texas Legislature:

- The legislature should clarify whether the 2005 legislation relating to advanced meters, PURA §39.107, applies to utilities outside of ERCOT.[1]

[1] *See* P.U.C. SUBST. R. 25.130(b), which states, "This section is applicable to all electric utilities, including transmission and distribution utilities, other than an electric utility that, pursuant to Public Utility Regulatory Act (PURA) §39.452(d)(1), is not subject to PURA §39.107; and to the Electric Reliability Council of Texas (ERCOT).

I. Smart Meters & the Smart Grid

A. Terms & Acronyms used in the Report

AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
AMS	Advanced Metering System
ANSI	American National Standards Institute
AMS/AMI	Advanced Metering System
ARRA	American Recovery and Reinvestment Act of 2009
BPL	Broadband Over Power-line
C&I	Commercial and Industrial Customers
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
DOE	Department of Energy
DLC	Direct Load Control
DLR	Dynamic Line Rating
DR	Demand Response
EE	Energy Efficiency
EISA	Energy Independence and Security Act of 2007
EPAct or Act	Energy Policy Act of 2005
FERC	Federal Energy Regulatory Commission
kW	Kilowatt
kWh	Kilowatt-hour (one thousand watt-hours)
MW	Megawatt
MWh	Megawatt-hour (one million watt-hours)
NERC	North American Electric Reliability Council
PLC	Power Line Communication
PURPA	Public Utility Regulatory Policies Act of 1978
REP	Retail Electric Provider
RF	Radio Frequency
RTP	Real-Time Pricing
SECO	State Energy Conservation Office
SGIG	Smart Grid Investment Grant Program
Smart Meters/Advanced Meters	Advanced Metering Infrastructure or System
TDU	Transmission Distribution Utility
TOU	Time-Of-Use (rate)
VPP	Variable peak pricing

B. Advanced Metering Systems & the Smart Grid

Today, most of the residential meters serving customers in the United States are simple electro-mechanical devices whose single function is to measure energy in kilowatt hours consumed by the customer. This technology, developed in the late 1800's, predates that of the rotary phone. If Alexander Graham Bell were confronted with today's telephony – cell phones, texting, etc., he would most likely be amazed. Thomas Edison, on the other hand, would feel quite at home in the largely non-digital, electromechanical landscape that is today's grid. Change is underway, however, to replace this aging technology with new smart meters. It is anticipated that by year end 2010, approximately 16 million smart meters will be in place in the U.S. This number is expected to reach more than 50 million by 2015.[2]

Advanced meters or "smart" meters, are digital devices that measure consumption and provide real-time feedback to customers on their electric usage. These meters have both information storage and continuously available, remote, two-way communication capability. This is in stark contrast to the aging electro-mechanical technology, in which meters must be individually read by utility personnel. With electro-mechanical meters, customers' only feedback related to their electric usage comes from their monthly bill.

Smart meters are an integral part of a utility's advanced metering infrastructure (AMI/ or AMS). AMI refers to the entire measurement and collection system which includes smart meters at the customer site, the associated hardware, software and back office communications systems and meter information networks for validating and processing meter information. Since the passage of HB 2129 in 2005, advanced metering technology has matured and AMI has become more sophisticated and cost effective.

AMI is an essential component of building a smart electricity grid.[3] Much more than just smart meters, the smart grid is an efficient, dynamic, and more resilient electrical and communications delivery system. Like the telecom and internet revolutions, technology holds the key to the smart grid and its benefits. The smart grid and the technologies embodied within it are an essential set of investments that will help bring our electric grid into the 21st century using megabytes of data to move megawatts of electricity more efficiently, reliably, and affordably. In the process, the electric system of today will

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[2] *A National Assessment of Demand Response Potential*, Staff Report, Federal Energy Regulatory Commission, June 2009, p. 230. This report estimates 32.5 million meters by 2012. DOE estimates 52 million meters will be installed by 2012. A statement by Patricia Hoffman, Acting Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy to the Subcommittee on Energy and Environment, Committee on Science and Technology, July 23, 2009.

[3] Jeffrey D. Taft, *AMI: Smart Enough?*, Public Utilities Fortnightly, 55 (June 2009).

move from a centralized, producer-controlled network to a less centralized, more consumer-interactive, more environmentally responsive model. Over time, benefits will encompass the broad areas of reliability, power quality, health and safety, national security, economic vitality, efficiency, and environmental impact.

Smart meters are expected to provide information to a distribution utility that will help it determine the scope of an outage and expedite the restoration of service. They are also expected to foster customers' elective participation in demand response programs that will reduce demand when wholesale prices are high or the electrical system is stressed. Another element of smart grid that is not supported by smart meters is better real-time information for grid operators about the status of the transmission lines, which should permit the transmission system to operate at higher loadings and permit less expensive generating units to operate when conventional grid management procedures would indicate that the system is congested.

A smart grid relies on the accurate, up-to-date and predictable delivery of data between the customer and the utility. AMI is one of the conduits by which this information is exchanged. AMI enables operational benefits and efficiencies for utilities and provides data collection and support for demand response and energy efficient behavior by consumers. Smart meters record electricity consumption at predetermined intervals, such as hourly, thirty minute, fifteen minute, or shorter as required. The meters then store and transmit the data through a secure network to utilities.

The data recording and communications functions of AMI allow utilities to effectively meet business and operational requirements for accurate collection of consumption data by interval and for the billing period. Examples of the operational efficiencies AMI provides to utilities include remote meter readings and remote disconnection and reconnection of service. In addition, the bi-directional communications capability of AMI allows utilities to quickly and accurately pinpoint where outages have occurred. Outage information sent from smart meters allows the utility to determine the extent of an outage and isolate the location of the damage, in some cases right down to the piece of equipment causing the outage. In some outages, some customers will be returned to service quickly and without the dispatch of a repair crew. Not having to search for the location of the problem should reduce the duration of an outage for all affected customers. This feature will allow utilities to recover from major, widespread outages caused by hurricanes or other weather events more quickly than prior to deployment of AMI.

AMI provides customers with the real time feedback allowing them to better understand their energy consumption, make more informed choices about energy use and conservation and participate in demand response programs. Two-way communication gives AMI the capability to transmit real-time prices and consumption data between the customer, the REP, and the utility, and provides information that the customer can act on, if he chooses. To deliver AMI's full benefits to Texans, economic signals must be delivered to the retail customer in the form of prices that are differentiated by time of day, either as time-of-use prices that are based on price trends in the wholesale market or as real-time prices that are based on real-time wholesale prices. The Federal Energy Regulatory Commission (FERC) has defined demand response as "a reduction in the consumption of electric energy by customers from expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."[4]

Demand for electricity varies with time. To meet this demand, generation units with varying efficiencies and fuel sources are used to insure that adequate electricity is constantly available to customers. Some generating units are expected to run most of the year, and these units typically have low fuel costs but high capital costs. Adequate generation capacity to serve peak demand must be maintained at all times. Certain generation units, due to their high fuel cost, operate during a relatively few hours per year when demand for electricity is the highest. These units typically have a low capital cost but high fuel cost. For this reason, the cost of service to customers is higher during peak hours than at other times.

Today's flat rates are average rates that do not directly reflect the time varying change in demand and real cost to serve customers. In other words, these rates mask the real cost to serve a customer at a particular time. As a result, there is no incentive on the customer's part to reduce or shift consumption during peak demand, since the customers are not directly charged for the high cost of electricity during these hours. In a competitive market, flat rates include a premium that reflects the risk that a retail provider bears in offering a flat, fixed retail rate, in the face of wholesale prices that are not known and will fluctuate. This premium compensates service providers who must absorb the cost of hedging the uncertainty associated with volatile wholesale prices.[5]

[4] *See* Order 719, 73 Fed. Reg. 64,100.
[5] Rick Morgan, *Rethinking Dumb Rates*, Public Utilities Fortnightly, 35-37 (March 2009).
In theory, customers who take on the added risk of price volatility associated with dynamic pricing should be relieved of the burden of a hedge premium since service providers are not incurring those costs.

Dynamic pricing (either time-of-use or real-time pricing) exposes retail customers who choose to participate in the pricing program to some of the volatility of wholesale prices. Prices are higher during peak periods to reflect the higher cost of providing electricity during those times and lower during off peak when it costs less to provide electricity. As a result, these customers have an incentive to reduce their consumption during peak periods, when prices are expected to be high. Customers may reduce demand by installing more efficient equipment, or participating in a demand response program or simply by deciding to turn off appliances when retail prices are high. Demand flattens over time as customers reduce consumption or shift it to off-peak hours, thereby reducing the need for investments in peaking generators. This demand response behavior is expected to lead to a lower clearing price for electricity.

Demand response through dynamic pricing is expected to be more effective when customers have ready access to price and consumption information through a mobile communications device, or an in home display (IHD) that communicates with the meter through a home area network (HAN). These small household devices provide real time energy consumption and can relay price signals based on the pricing plan the customer has elected. When used in conjunction with smart appliances, the demand response benefits are magnified even further. Customers can easily set preferences to control a smart appliance, such as a programmable thermostat, to respond to price signals and other electric power system conditions. AMI enables customers to better understand their energy consumption and provides the visibility customers need to make a demand response decision. It is up to the customer or the customer’s agent, however, to make time-differentiated pricing plans and demand response programs available that will give customers the tools to act on the information received. The customer’s agent could be the REP offering an innovative rate plan or demand response program or a third party offering a demand response program.

AMI is the cornerstone and the essential building block of a smart grid. A smart grid is an efficient, dynamic and more resilient electrical and communications delivery system. FERC Chairman John Wellinghoff summarizes a smart grid this way: “We believe the Smart grid is best defined as providing consumers the opportunity to communicate with and participate in the electric system in ways that can control their costs.”[6] A recent DOE assessment concluded that part of the vision for a smart grid is to make customers an integral part of the electric power system by enabling them to make informed decisions regarding their energy usage. By enabling informed participation through a bi-directional flow of both energy and information that allows customers to modify the way

[6] *Smart Grid Heavy Hitters Series*, Green Monk, April 15, 2010.

they use and purchase electricity, a smart grid helps balance supply and demand and increase system reliability.[7]

The creation of a smart grid is not a single event but occurs over time with AMI deployment and other upgrades and improvements to utilities' transmission and distribution systems. Working in conjunction with the National Energy Technology Laboratory (NETL), electric grid stakeholders representing utilities, technology providers, researchers, policymakers, and customers have defined the following functions or attributes of a smart grid:

- Self-healing from power disturbance events;
- Enabling active participation by consumers in demand response;
- Operating resiliently against physical and cyber attack;
- Providing power quality for 21st century needs;
- Accommodating all generation and storage options;
- Enabling new products, services and markets; and
- Optimizing assets and operating efficiently.

As technology solutions are deployed that enable a smart grid to attain these attributes, a variety of far reaching benefits follow. Benefits flow from the broad areas of reliability, power quality, health and safety, national security, economic vitality, efficiency and environmental impact. Some specific benefits include:

- Increased security and durability in response to attacks or natural disasters;
- Reduction in restoration time and reduced operation and maintenance costs due to better information about customers without service and the integration of predictive analytics, self diagnosis and self healing technologies;
- More efficient transmission and generation of electricity;
- Reduction in transmission congestion costs, leading to more efficient electricity markets;
- Improved power quality and reliability;
- Environmental benefits gained by more efficient grid operation;
- Increased capital investment efficiency due to tighter design limits and optimized use of grid assets;
- Increased integration of distributed generation and renewable energy;
- Higher transmission and distribution capacity utilization;
- Reduced peak demand; and

[7] Statement of Patricia Hoffman, Acting Assistant Secretary for Electricity Delivery and Energy Reliability, U.S. Department of Energy, Report to Subcommittee on Energy and Environment Committee on Science and Technology, U.S. House of Representatives, July 23, 2009.

- Improved U.S. competitiveness resulting in lower prices for U.S. goods and greater job creation. [8]

C. Federal Policy Regarding AMS and the Smart Grid

The Energy Policy Act of 2005 (Act) modified the Public Utility Regulatory Policies Act of 1978 (PURPA) to establish a policy framework for the deployment of demand response and AMI technologies. The Act directed FERC to provide annual regional assessments of demand response resources, the penetration of smart metering and other technologies, and identify any barriers to the adoption of these. The Act represented the first time that development of the smart grid was set as a national priority.

The Energy Independence and Security Act of 2007 (EISA) expanded federal support for investments in smart grid. EISA directed FERC to conduct a national assessment of demand response potential, develop a national action plan on demand response, and, with DOE, develop a proposal to implement the national action plan. FERC was ordered to identify the requirements for technical assistance to states to help them optimize the amount of DR that can be developed and implemented and the requirements for a national communications program for broad-based customer education and support, and to develop or identify the analytical tools, information, model regulations and contracts for customers, states, utilities and DR providers. EISA directed DOE to identify any regulatory and technological barriers to widespread installation, directed the National Institute of Standards and Technology (NIST) to develop nationwide standards for smart grid technologies and provided funding, in the form of matching funds, for smart grid investments. EISA also directed states to encourage utilities to employ smart grid technology and allow utilities to recover smart grid investments through rates.

The American Recovery and Reinvestment Act (ARRA) of 2009 set aside $4.5 billion for the DOE Smart Grid Investment Grant (SGIG) program, aimed to improve the reliability of electric energy and storage infrastructure, to accelerate the modernization of the electric transmission and distribution systems, and promote investments in smart grid technologies to increase flexibility, functionality, interoperability, cyber security, and operational efficiency.

[8] *Understanding the Benefits of the Smart Grid*, U.S. Department of Energy, National Energy Technology Laboratory, June 18, 2010.

In January 2010, NIST released the Framework and Roadmap for Smart Grid Interoperability Standards which identified eight priorities for standards developments, provided an initial list of standards, set out a preliminary cyber security strategy, and other elements of a framework to support transforming the country's electric power system into an interoperable smart grid.[9]

In June 2010, FERC released the National Action Plan on Demand Response report which identifies strategies and activities to achieve the three objectives of technical assistance to states, a national communication program, and the development or identification of tools and materials that can be used by customers, states, and DR providers. Central to the plan is the formation by the public and private sector of a coalition to help states and regions develop and deploy successful and cost-effective DR programs. The plan for tools and materials provides for creating a web-based clearinghouse, and tools and methods for assessing the impacts, costs, benefits, and operation of DR programs.[10]

In July 2010, DOE launched a beta version of a new smart grid information clearinghouse web portal (the full version to be released in fall 2010), to provide information on technologies, standards, rules and regulations, industry use cases and case studies, training and best practices and to track smart meter deployments across the country and overseas.[11] It is also intended to serve as a decision support tool for state and federal regulators in rulemaking and evaluating the impact of their investments in smart grid technologies.[12]

D. Texas Policy Regarding AMS and the Smart Grid

In 2005, the 79th Texas Legislature passed House Bill (HB) 2129 to encourage the implementation of smart metering by directing the Commission to establish a nonbypassable surcharge for a utility to recover reasonable and necessary costs incurred in deploying advance metering and metering information networks. Although HB 2129

[9] *NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0,* National Institute of Standards and Technology, Jan. 2010, available at http://www.nist.gov/public_affairs/releases/upload/smartgrid_interoperability_final.pdf.
[10] *National Action Plan on Demand Response*, Federal Energy Regulatory Commission, June 17, 2010, available at http://www.ferc.gov/legal/staff-reports/06-17-10-demand-response.pdf.
[11] http://www.sgiclearinghouse.org/.
[12] *Virginia Tech Posts Beta Version of Smart Grid Information Clearinghouse*, July 7, 2010, http://www.smartgrid.gov/news/clearinghouse_beta.

did not require that smart meters be deployed by utilities in Texas, the intent was quite clear:

> In recognition that advances in digital and communications equipment and technologies have the potential to increase the reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of generation assets and transmission and generation assets, and provide more choices for consumers, the legislature encourages the adoption of these technologies by electric utilities in this state.[13]

The 80th Texas Legislature re-iterated this encouragement when it stated in HB 3693:

> It is the intent of the legislature that net metering and advanced meter information networks be deployed as rapidly as possible to allow customers to better manage energy use and control costs and to facilitate demand response initiatives.[14]

Pursuant to HB 2129, the Commission adopted a rule which addresses: 1) the minimum functionality to qualify for a cost recovery surcharge; 2) the process for an electric utility to notify the Commission and REPs of the deployment of smart metering; and 3) the cost recovery surcharge for AMI deployment.[15]

Under the Commission rule, deployment of AMI is voluntary. The rule takes a flexible approach to AMI deployment in order to accommodate future innovations. The Commission concluded that a comprehensive set of AMI functions was necessary to achieve the benefits in HB 2129. Standardization of capabilities across ERCOT is also extremely important for REPs offering products to customers in multiple utility territories. Therefore, AMI deployed by a utility pursuant to the rule must support the following functions:[16]

- Automated meter reading;
- Two-way communications;
- Remote disconnection and reconnection capability;
- The capability to time-stamp meter data sent to ERCOT or a regional transmission organization for purposes of wholesale settlement;
- The capability to provide direct, real time access to customer usage data to the customer and customer's REP;
- Means by which the REP can provide price signals to the customer;

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[13] HB 2129 § 8(a), 79th Leg. R.S.
[14] HB 3693 § 20(i), 80th Leg. R.S.
[15] P.U.C. SUBST. R. 25.130.
[16] P.U.C. SUBST. R. 25.103(g)(1).

- The capability to provide 15-minute data or shorter interval data to REPs customers, and ERCOT or a regional transmission organization;
- On-board meter storage of meter data that complies with nationally recognized non-proprietary standards such as ANSI C12.22;
- Capability to communicate with devices inside the premises, including usage monitoring devices, load control devices, and prepayment systems through a home area network (HAN) based on open standards and protocols that comply with nationally recognized non-proprietary standards such as ZigBee, Home-Plug or the equivalent;
- The ability to upgrade these minimum capabilities as technology advances and they become economically feasible.

The rule includes requirements for access to meter data, the deployment plan filed by the utility, and provisions for cost recovery. Since the rule was adopted in May 2007, the Commission has worked closely with utilities, REPs', consumer groups, ERCOT, and other stakeholders to implement the rule.

HB 2129 states that the customer owns meter data:

> All meter data, including all data generated, provided, or otherwise made available, by advanced meters and meter information networks, shall belong to a customer, including data used to calculate charges for service, historical load data, and any other proprietary customer information.[17]

Therefore, as AMI is deployed, customers will neither be assessed a fee or be required to obtain permission to view their data. Currently, customers that have a smart meter and a HAN device installed may view their consumption data in real time. HAN devices that show electrical usage may be purchased by the customer or may be provided by REPs or other third parties.

Since the report on advanced metering to the 81st Texas Legislature, ERCOT, in compliance with the Commission's rule and HB 2129, has revised its settlement process. In late 2009, ERCOT implemented a new settlement solution that settles load entities' energy and capacity market obligations with usage data based on 15 minute intervals for customers equipped with advance meters. This provides significant benefits to both the customer and the REP. Settling on the basis of a customer's usage data in 15 minute intervals provides a more accurate settlement for REPs and allows them to design innovative pricing products, including products that provide time-differentiated price

[17] PURA § 39.107(b).

signals. With increased visibility to both their usage patterns and time-differentiated price signals, customers may participate in demand response programs to shift load to off-peak, less costly hours or install more efficient appliances to reduce consumption, particularly peak-period consumption.

Fifteen minute consumption data is now available in a centralized or common web portal (Smart Meter Texas) and may be accessed by customers, REPs and ERCOT. This means customers with an advanced meter in the AEP Texas, Oncor or CenterPoint utility footprint can go to the same website for their consumption information. This web portal, shared jointly by these utilities, was launched in the Spring of 2010 and is ADA compliant. Customers can see their usage data in 15-minute increments, and can connect an IHD or HAN device to their meter through this website. In addition, it is a tool for REPs to send signals to their customers with devices inside the home, provided those customers elect to receive those signals. This initiative was a huge undertaking, as it provides a central clearinghouse of information for all the TDUs in ERCOT to provide information and tools to customers with a smart meter. This is the only web tool of its kind in the United States.

The Commission adopted an expedited cost recovery process for transmission and distribution utilities in the rule. The rule permits the Commission to establish a surcharge for an electric utility to recover reasonable and necessary costs in deploying AMS to residential and nonresidential customers. The rule permits the surcharge to be based on an estimate of reasonable costs, less any expected utility savings, but it also includes periodic reconciliations of costs, savings, and revenues, so that a utility may not recover more than its reasonable costs less its savings.

The Commission addressed the type of cost information to include in a surcharge request in Project No. 33874, *Form for Transmission and Distribution Utility Advanced Metering Infrastructure Surcharge*. The Commission approved a model in this project, which analyzes the costs and benefits of deploying AMI in a utility service territory.

II. ARRA Funding

Title IV of the American Recovery and Reinvestment Act of 2009 (ARRA) provided the DOE $32.7 billion in grant funding for energy projects, including $4.5 billion allocated in relation to "Electric Delivery and Energy Reliability," specifically authorizing funds for electric grid modernization.[18] The ARRA grants have significantly changed the speed and scale of smart metering implementation by infusing funds towards smart grid deployment, demonstration projects, energy assurance and regulatory assistance. It is estimated that the funding will result in the installation of 18 million new smart meters nationwide.[19] According to DOE, 169 such projects have been funded in Texas.[20]

The Commission applied for and was granted $1,370,056 under the State Electricity Regulators Assistance program. ARRA provided the DOE $46 million for state level electric utility regulators, with the following goals:

- Increase the capacity of state PUCs to manage a significant increase in dockets and other regulatory actions resulting from ARRA electricity-related topical areas;
- Facilitate timely consideration by PUCs of regulatory actions pertaining to ARRA electricity-related topical areas; and
- Create jobs.[21]

The stimulus funds are being managed by the Competitive Markets Division (CMD), with oversight by Commission management and executives. The CMD will use the funding to handle regulatory dockets regarding topical areas to include energy efficiency, renewable energy, energy storage, smart grid, plug-in electric vehicles, demand response, coal with carbon capture and storage, and transmission and distribution as permitted by ARRA. With regards to smart metering and smart grid, PUCT must approve smart grid investments of utilities receiving ARRA funding, as well as the required matching funding from the recipients. PUCT must also approve the surcharges passed through to

[18] ARRA H.R. 1-24 "Electricity Delivery and Energy Reliability" states that "funds shall be available for expenses necessary for electricity and energy reliability activities to modernize the electric grid, to include demand responsive equipment, enhance security and reliability of the energy infrastructure, energy storage research, development, demonstration and deployment, and facilitate recovery from disruptions to the energy supply, and for implementation of programs authorized under title XIII of the Energy Independence and Security Act of 2007."

[19] *Follow the Money: Stimulus Funding Begins to Flow into the Smart Gird Sector*, KEMA Automation Insight, (Feb. 2010), available at http://www.kema.com/services/consulting/utility-future/smart-grid/follow-the-money-stimulus-funding-begins-to-flow-into-smart-grid-section.aspx.

[20] American Recovery and Reinvestment Act of 2009, Department of Energy breakdown, available at http://energy.gov/recovery/breakdown.htm.

[21] Funding Opportunity Number: DE-FOA-0000100, available at http://www.energy.gov/recovery/documents/DE-FOA-0000100.pdf.

ratepayers for AMS. The grant will fund the creation of up to seven new positions in CMD.

Additionally, the Infrastructure and Reliability Division (IRD) of PUCT received pass-through stimulus funding from the State Energy Conservation Office (SECO). ARRA provided DOE $39.5 million as part of "The Enhancing State Government Energy Assurance Capabilities and Planning for Smart Grid Resiliency Initiative" (State EA Initiative) with the following goals:

- Strengthen and expand state and local government energy assurance planning and resiliency efforts by incorporating response actions for new energy portfolios and smart grid applications;
- Create jobs; and
- Build in-house state and local government energy assurance expertise.[22]

SECO, the lead entity of the Texas EA Program, was awarded a grant of $2,432,068. The Commission received a sub-award of $1,697,458 from SECO for its role in managing cyber-security concerns, incorporating smart metering technologies into the electric grid, and managing electric energy assurance planning for the State. Energy Secretary Stephen Chu when announcing the funds acknowledged that "enhancing the states' ability to quickly and effectively respond to energy disruptions is a critical element in meeting our nation's energy goals."[23] The Railroad Commission of Texas also received a sub-award under the State EA Initiative, and the Commission and Railroad Commission will update the State of Texas Emergency Management Plan, Annex L regarding energy and utilities, in coordination with a variety of other entities including ERCOT.[24] The awarded stimulus will fund up to four new positions in IRD.

A. Texas Recipients of ARRA Funds

Under ARRA's "Electric Delivery and Energy Reliability" provision, $3.5 billion will be directed to the SGIG with the goal of accelerated deployment of grid modernization.[25] DOE's defined goals in establishing the SGIG include:

- Enabling informed participation by consumers in retail and wholesale electricity markets;

[22] Funding Opportunity Number: DE-FOA-0000091, available at https://www.fedconnect.net/FedConnect/?doc=DE-FOA-0000091&agency=DOE.
[23] Se*cretary Chu Announces Nearly $38 Million in State Awards for Energy Emergency Preparedness*, Department of Energy (2009, August 12), available at http://www.energy.gov/news2009/7791.htm.
[24] SECO Stimulus |State Energy Conservation Office, "Energy Assurance Program", available at http://www.seco.cpa.state.tx.us/arra/ea/index.php.
[25] The Smart Grid Investment Grant Program is authorized by EISA, Title XIII, Section 1306 as amended by ARRA.

- Accommodating all types of central and distributed electric generation and storage options;
- Enabling new products, services and markets;
- Providing for power quality for a range of needs by all types of customers;
- Optimizing asset utilization and operating efficiency of the electric power system;
- Anticipating and responding to system disturbances; and
- Responding resiliently to attacks and natural disasters.[26]

The five SGIG program funds recipients in Texas were awarded a total of $258 million for smart grid initiatives, including projects relating to transmission and distribution systems end-use-consumer metering, and energy efficiency.

1. CenterPoint Energy

CenterPoint Energy (CenterPoint) received an SGIG award of $200 million towards funding its Houston-based smart grid initiative. This amount includes $150 million for advanced metering (AMS) and represents 23.5 % of the $639 million required to deploy AMS. The remaining $50 million will be used for the intelligent grid.[27] CenterPoint was one of only six utilities nationwide selected by DOE to receive the maximum $200 million available to large projects under ARRA. The company serves 2.1 million metered electric consumers in the Houston area, accounting for approximately 15% of the total electric consumption in Texas.[28] In December 2008, the Commission approved CenterPoint's plan to deploy over two million smart meters; the first meter outside its initial pilot was installed in February 2010. CenterPoint plans to use $150 million of the SGIG funds to accelerate AMS deployment completion by an estimated two and a half years, and the remaining $50 million to offset CenterPoint's $100 million Intelligent Grid infrastructure automation project.[29] Upon the completion of phase one IG construction, approximately 29 automated substations, along with approximately 579 automated switches, substation and distribution line monitors, and remote terminal units will be installed.

The electric distribution customers in CenterPoint's service territory will see various long-term benefits from the smart grid, including time-differentiated pricing and

[26] Funding Opportunity Number: DE-FOA-0000058, available at https://www.fedconnect.net/FedConnect/?doc=DE-FOA-0000058&agency=DOE.
[27] CenterPoint Energy Smart Grid Project, available at http://www.smartgrid.gov/index.php?q=project/centerpoint-energy-smart-grid-project.
[28] *CenterPoint Energy Stimulus Grant Facts* (2009, October), available at http://www.centerpointenergy.com/staticfiles/CNP/Common/SiteAssets/doc/energy%20insight%20stimulus%20grant%20facts.pdf.
[29] *Ibid*.

improved response times in the case of a major outage event, such as a hurricane, with the expectation that customers will be returned to service up to 50% faster.[30] The electricity market as a whole will gain insight from the extensive data CenterPoint will provide DOE regarding full scale smart grid deployment in a deregulated competitive market.

2. El Paso Electric

El Paso Electric Company (EPE) was awarded a one million dollar grant through the SGIG program, to fund 46.2% of its $2,196,187 smart grid project.[31] EPE, an integrated, regulated utility, serves approximately 370,000 metered electric customers in the El Paso area and Southern New Mexico. The ARRA funds will go towards automating distribution management system and instituting self-healing systems to restore service in emergency situations.[32]

3. Golden Spread Electric Cooperative

Golden Spread Electric Cooperative received $20 million in SGIG funds, providing a 40% cost share towards the $49,987,500 total project cost.[33] Golden Spread is a consortium of 16 member distribution co-ops located throughout rural areas of the Texas Panhandle, South Plains, Edwards Plateau, the Oklahoma Panhandle, Southwest Kansas and Southeast Colorado.[34] The cooperative serves 213,000 electric consumer members in ERCOT and the Southwest Power Pool (SPP). The SGIG award was granted to integrate supply and demand in the smart grid. Eleven member co-ops will install 70,000 smart meters, with plans for full deployment as funds become available.[35] Golden Spread will also use the grant towards building an enhanced cyber security system, and accelerating the installation of communication devices and associated databases at the substations level.[36]

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[30] *Ibid*.
[31] El Paso Electric Smart Grid Project, available at http://www.smartgrid.gov/project/el-paso-electric-smart-grid-project.
[32] *El Paso Electric Implements FASTapps From Efacec ACS as First Phase in Smart Grid Program* (June 10, 2010), available at http://www.prnewswire.com/news-releases/el-paso-electric-implements-fastapps-from-efacec-acs-as-first-phase-in-smart-grid-program-96088519.html.
[33] Golden Spread Electric Cooperative, Inc. Smart Grid Project available at http://www.smartgrid.gov/project/golden-spread-electric-cooperative-inc-smart-grid-project.
[34] Golden Spread Electric Cooperative, Inc. | 2009 Annual Report, available at http://www.gsec.coop/pdfs/2009.pdf.
[35] "Golden Spread gathers 11 G&T co-ops for big SGIG-supported rollout", Smart Grid Today, (December 4, 2009), available at http://www.smartgridtoday.com/members/1012.cfm.
[36] *Ibid*.

Consumers will benefit from the energy use monitoring capabilities and reduced outage recovery times, and they will gain the capability for remote restarts of irrigation equipment following a service disruption.[37]

4. Denton County Electric Cooperative

A second Texas electric co-op, Denton County Electric Cooperative (dba, CoServ), also received an ARRA grant through DOE. CoServ received an SGIG grant of $17 million to fund 42% of its $40,966,296 project.[38] Serving Denton, Collin, Tarrant, Cooke, Grayson and Wise counties in North Texas, the co-op is the second largest electric distribution cooperative in Texas with over 150,000 meters in the territory.[39] CoServ is using the SGIG funding to support the eventual full deployment of approximately 140,000 smart meters to residential and commercial customers. Over 7,000 residential and 6,500 C&I electronic meters have already been deployed and tested within industry standards.[40]

The project includes distribution network modernization, two-way communication and computer systems.[41] Stimulus funds will help CoServ accelerate the deployment schedule to permit the completion of the project two years sooner than originally estimated.[42] Consumers will benefit from electric rates tailored to customer class, to TOU plans and eventually real-time pricing.[43] CoServ is also planning a significant amount of customer education as part of the initiative.

5. Reliant Energy Retail Services

Reliant Energy Retail Services (Reliant) was the only REP to receive SGIG funding in Texas. Reliant received $20 million to fund 31.1% of its $63,696,548 smart grid project.[44] Reliant will use the SGIG funding for the deployment of products and tools utilizing smart meter two-way communication functionality to its 1.6 million retail electric customers in Texas. This will include accelerated development of TOU rate

[37] Golden Spread Electric Cooperative, Inc. | 2009 Annual Report, available at http://www.gsec.coop/pdfs/2009.pdf.
[38] Denton County Electric Cooperative, d/b/a CoServ Electric. Smart Grid Project, available at http://www.smartgrid.gov/project/denton-county-electric-cooperative-dba-coserv-electric-smart-grid-project.
[39] CoServ Electric | 2009 Annual Report, available at http://www.coserv.com/Portals/0/PDFs/Annual%20Reports/AnnualReport2009_web.pdf.
[40] Ibid.
[41] Denton County Electric Cooperative, d/b/a CoServ Electric. Smart Grid Project, available at http://www.smartgrid.gov/project/denton-county-electric-cooperative-dba-coserv-electric-smart-grid-project.
[42] "SGIG AMI awardees plan for big goals, plentiful apps," Smart Grid Today, (2009, November 13), available at http://www.smartgridtoday.com/members/951.cfm.
[43] *Ibid*.
[44] Reliant Energy Retail Services, LLC Smart Grid Project, available at http://www.smartgrid.gov/project/reliant-energy-retail-services-llc-smart-grid-project.

plans, email alerts that provide intra-month insights into consumption and projected bill amounts, a customer web portal and home energy monitoring devices to the competitive electric choice market.[45] The company hopes to educate and demonstrate the benefits of Smart Grid enabled products and services for Texas consumers. In addition, they plan to increase customer use of the smart grid enabled product and service offerings to 500,000 customers by 2013.

Jason Few, president at Reliant, stated when announcing the grant, "Reliant is committed to revolutionizing the way people interact with energy through technology by continually pushing to develop and deliver innovative energy solutions to improve the lives of our customers, this grant will help us get those services into the hands of more customers."[46] In July 2010, Reliant launched '*energywise',* a web portal to educate consumers on energy savings options, smart energy devices and the benefits of smart metering. Electric consumers in Texas will benefit from the increased integration of smart grid into their homes and businesses. Reliant's SGIG project aims to accelerate the delivery of tools to help consumers realize the savings and efficiencies that a smart grid can provide.

In addition to the SGIG program, DOE awarded $620 million in ARRA funding to thirty-two Smart Grid Demonstration Programs (SGDP).[47] Participants in smart grid demonstration projects will report program results to DOE for future nationwide replication and deployment. Special focus will be given to several quantifiable metrics, including:

- Job creation and marketplace innovation;
- Peak demand and electricity consumption reduction;
- Operational efficiency;
- Grid reliability and resilience;
- Distributed energy resources and renewable energy integration; and
- Carbon dioxide emission reduction.[48]

[45] Harris County, Texas | ProPublica Recovery Tracker, Reliant Energy Retail Services, LLC, available at http://projects.propublica.org/recovery/locale/texas/harris.
[46] *Reliant Energy and DOE Finalize $20 Million Stimulus Grant Agreement To Expand Rollout of Smart Energy Solutions to Texas Residents*, Reliant Energy, (2010, March 31), available at http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9Mzg3Nzh8Q2hpbGRJRD0tMXxUeXBlPTM=&t=1.
[47] The Smart Grid Demonstration Program is authorized by EISA, Title XIII, Section 1304 as amended by ARRA.
[48] "Guidebook for ARRA Smart Grid Demonstration Program and Renewable and Distributed Systems Integration Program metrics and Benefits", Department of Energy (2010, June), available at http://www.oe.energy.gov/DocumentsandMedia/09_SG_Kickoff_Guidebook.pdf.

The three SGDP recipients in Texas were awarded a total of $27,391,797 for smart grid demonstration projects, which integrate technologies on both the utility and consumer sides of the meter.

6. Oncor Electric Delivery Company (Oncor)

Oncor was the only Texas TDU to receive funding under the SGDP program. The TDU, headquartered in Dallas, was awarded $3.4 million to fund 47.7% of its $7,279,166 demonstration project.[49] The project will install dynamic line rating (DLR) equipment on eight high-voltage transmission lines subject to congestion in the following Central Texas counties: Bell, Bosque, Falls, Hill, McLennan and Williamson.[50] Using real-time information, the devices will transmit data indicating the level of loading of the lines at a given time, with the goal of improving electricity delivery and reliability.[51] Oncor hopes to demonstrate optimized grid performance through the DLR project and prove quantifiable cost savings through automation.

7. CCET Smart Grid Demonstration Project

The Center for the Commercialization of Electric Technologies (CCET) received $13.5 million from the DOE to fund 49.3% of its $27,419,424 demonstration project.[52] The members of the Austin based non-profit organization are twenty-two Texas electric market participants, including TDUs, REPs, high-tech companies and academic institutions.[53] CCET will use the grant to fund three separate projects aimed at "[enhancing] the security, reliability and efficiency of the electric infrastructure in Texas through research, development, demonstration and commercialization of advanced technologies."[54]

The SGDP projects include deploying the use of devices to measure the effects of variable wind generations on the ERCOT transmission grid and using smart metering infrastructure information for enhanced load control.[55] The third CCET project utilizing

[49] Oncor Electric Delivery Company, LLC Smart Grid Demonstration Project, available at http://www.smartgrid.gov/project/oncor-electric-delivery-company-llc-smart-grid-demonstration-project.
[50] *Oncor Seeks Stimulus Funds for Real-Time Dynamic Transmission Line Study*, Oncor, (2009, August 26), available at http://www.oncor.co/news/newsrel/detail.aspx?prid=1214.
[51] *Ibid*.
[52] Center for the Commercialization of Electric Technologies Smart Grid Demonstration Project, available at http://www.smartgrid.gov/project/center-commercialization-electric-technologies-smart-grid-demonstration-project.
[53] *Texas Selected for Department of Energy Regional Demonstration Project*, CCET, (2009, November 24), available at http://electrictechnologycenter.com/news/ccet_doe_grant.html.
[54] Ibid.
[55] *DOE Awards $13.3-Million Grant That Will Benefit Discovery at Spring Trails, Texas's First Smart Grid Community*, ElectricEnergyOnline.com, (March 23, 2010), available at http://www.electricenergyonline.com/?page=show_news&id=130060.

the stimulus funds will be development of Discovery at Spring Trails, located in the Houston suburbs, as a "smart grid community of the future."[56] The 3,000-home project will combine energy-efficient building standards with smart grid enabled appliances, home energy monitoring devices, electric vehicles and solar distributed generation.[57] CCET estimates the SGDP award will help fund the project through 2015.

8. Pecan Street Project

The Pecan Street Project received $10.4 million in SGDP funding, contributing 42.2% towards its $24,656,485 demonstration project.[58] The Austin-based initiative is a collaboration between Austin Energy, the University of Texas, Environmental Defense Fund, the Austin Chamber of Commerce and the City of Austin, with input from ERCOT, Bluebonnet Electric Cooperative, CPS Energy, and the Pedernales Electric Cooperative.[59] The grant will help fund the re-development of the Austin Muller neighborhood as a micro-grid, connecting 1,000 residential and 75 commercial smart meters, and facilitating distributed generation and electric vehicle charging. Additional technologies the development will explore include energy storage, solar generation, smart metered water systems and smart enabled appliances.

The Pecan Street Project will demonstrate how these emerging technologies interact with the electric grid and natural resources, eventually providing a roadmap for implementation and scale-up in larger markets. From the beginning of the project, there has been a desire for the community to be a laboratory for electric grid modernization and interaction.

9. Texas A&M University

Texas A&M University was awarded a $10 million grant by the U.S. Department of Energy to help fund a new combined heat and power (CHP) generation system. The new CHP generation equipment is being installed at the university's central utility plant and is scheduled to be operational by August 2011.

The $70.25 million CHP project will allow the university to provide up to 50 MW of generation while reducing overall energy consumption and greenhouse gas emissions. A number of new facilities on campus have increased demand for energy, and square footage in the hundreds of buildings on campus have increased from 18.5 million gross

[56] *Ibid*.
[57] *Ibid*.
[58] Pecan Street Project, Inc. Smart Grid Demonstration Project, available at http://www.smartgrid.gov/project/pecan-street-project-inc-smart-grid-demonstration-project.
[59] *Ibid*.

square feet in 2002 to 22 million in 2010. Construction on the CHP project is under way in the central utility plant, which also includes the installation of almost two miles of electrical duct bank and feeders on campus. The CHP project includes the installation of two turbine generators and a boiler, an upgrade of the electrical distribution system, and other improvements. Major construction work on the project will continue through the end of 2011.

IV. Implementation of Smart Meters and Advanced Systems

A. Deployment in Texas

The three largest investor owned utilities in ERCOT, CenterPoint, Oncor and AEP Texas, are all at varying stages of deployment. Texas New Mexico Power (TNMP) filed a request for approval of deployment and a surcharge in May of 2010. That case is currently ongoing.[60]

CenterPoint received approval in December 2008 for its deployment. The Commission approved an unopposed settlement that was reached among consumers, staff, cities, REPs and other interveners in the docket.[61] CenterPoint intends to deploy just over 2.1 million meters over the period 2009 through mid-2012, with an AMI that meets the requirements of the Commission's smart metering rule.[62] In CenterPoint's deployment plan, $5.6 million dollars is set aside for customer education and an additional $7.5 million to provide IHDs for low-income customers.

CenterPoint continues to operate its Technology Center in Houston. This Technology Center demonstrates the company's vision for AMI and its future Intelligent Grid. The center includes a display that features the advanced metering system and the other functions it can perform. CenterPoint has given over 500 tours to the public, Commission staff, and policy makers from local, regional and national levels, as well as utilities from around the world. As of August 31, 2010, CenterPoint has installed 615,518 smart meters. To date, CenterPoint has received $53.5 million of the $150 million DOE Smart Grid Investment Grant award to offset the costs of the accelerated AMS deployment.

Oncor Electric Delivery Company received approval for its deployment in August, 2008.[63] The Commission approved a unanimous settlement reached among parties in the docket, including staff, cities, consumers, and REPs. Oncor intends to deploy approximately 3.4 million smart meters, completing deployment in 2012, with a system that will meet the requirements of the Commission's advanced metering rule. In Oncor's

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[60] *Texas New-Mexico Power Company's Request for Approval of Advanced Metering System (AMS) Deployment and AMS Surcharge*, Docket No. 38306.

[61] *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System,* Docket No. 35639.

[62] CenterPoint has requested to accelerate the deployment of smart meters as result of the DOE Smart Grid Investment Grant Award, in the AMS Reconciliation as part of its rate case, *Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates,* Docket No. 38339.

[63] *Oncor Electric Delivery Company LLC's Request for Approval of Advanced Metering System (AMS) Deployment Plan and Request for Advanced Metering System (AMS) Surcharge,* Docket No. 35718.

deployment plan, $15 million is set aside for customer education and $10 million to fund a program to distribute IHDs for low-income customers. As of August 31, 2010, Oncor has installed 1,251,838 smart meters.

Oncor's AMI deployment also includes a comprehensive customer education program called "SMART TEXAS - *rethinking energy"* that works in tandem with Oncor's deployment of AMI technology to educate retail electric customers about the potential benefits that can be achieved through the use of a smart meter. The program includes a Mobile Experience Center (a hands-on educational tool that travels throughout Oncor's service territory in advance of the deployment), educational door hangers, and newspaper, billboard and movie theater advertisements. This education effort is important to empower customers to take action themselves to realize some of the potential benefits.

AEP Texas received approval from the Commission to deploy approximately 1.1 million meters in its territory in December 2009. The Commission approved an unopposed settlement that was reached among consumers, staff, cities, REPs and other interveners in the docket.[64] AEP Texas intends to deploy these meters in its Texas North and Texas Central territories over the next 4 years. Consistent with Oncor and CenterPoint deployments, AEP has included $5 million for customer education and $1 million to provide IHDs for low-income customers. As of August 31, 2010, AEP Texas has installed 78,705 smart meters in TNC and TCC.

AEP Texas gridSMART^{SM} initiative includes a comprehensive customer education program developed jointly with PUCT staff to help retail electric customers understand the potential benefits of the smart meter deployment. Like Oncor, AEP Texas education program includes a Mobile Demonstration Unit that will travel throughout AEP Texas vast service area in advance of their meter deployment. Educational door hangers and brochures have been developed and are used to reach as many customers as possible.

B. Market Implementation Effort

Following the adoption of the advanced metering rule that provides a structure for deployment and cost recovery, the Commission opened Project No. 34610 to address the implementation of AMI, including the impacts on the ERCOT retail and wholesale markets and to ensure that customers receive benefits from AMI investments. Many of

[64] *Application of CenterPoint Energy Houston Electric, LLC for Approval of Deployment Plan and Request for Surcharge for an Advanced Metering System,* Docket No. 35639.

the issues in this project are complex and interdependent, and the implementation affects all market segments. Realizing the benefits of deployment in Texas has required a fine tuning of existing market processes and will continue to require modifications to substantive rules, ERCOT Protocols and market guides; system changes for REPs, utilities and ERCOT; new transactions and modification of existing transactions; new business processes; and new data transport mechanisms.

The implementation project led by commission staff, has included broad involvement of market participants including utilities, ERCOT staff, vendors, consumers, REPs and others. The project has focused on five major areas: home area networks; access to customer data and related security; ERCOT settlement; changes to retail market processes; and customer education.

1. Access to Customer Data

AEP Texas, CenterPoint and Oncor worked collaboratively with stakeholders to create an online web portal for customers and their designated agents, ERCOT and REPs to access consumption data. This web portal, SmartMeterTexas, was launched in the Spring of 2010. The web portal is ADA compliant, and standardizes functionalities and data access across TDUs within ERCOT, with consistent content, availability and data format. This web portal allows REPs to take full advantage of the AMI deployed, and develop retail electric services that incorporate dynamic pricing and demand response for residential and small commercial consumers. This standardization ensures that REPs, customers and their agents have access to the same basic information in every territory, and that REPs do not have to develop different systems and processes for providing customer products in each TDU territory.

2. Settlement

The ERCOT ISO achieved a significant milestone in December 2009 when it began settling wholesale obligations using customers' 15-minute consumption data. In order to achieve this milestone, ERCOT dedicated significant amount of resources to make modifications to its systems. ERCOT is the only ISO in the country that is performing this level of complex settlement for customers with smart meters. P.U.C. SUBST. R. 25.130(h) states that ERCOT shall be able to use 15-minute interval data from smart meters for wholesale settlement purposes no later than January 31, 2010.[65] ERCOT has developed a method for achieving settlement in the short term to meet the goal in the rule.

[65] P.U.C. SUBST. R. 25.130(h).

3. Home Area Network

The HAN is an integral feature for realizing benefits of Smart Meter deployment in Texas. A recent survey reported that over 80% of consumers in the U.S. are interested in learning how to cut electricity costs. This survey also reported that 80-85% of households are willing to pay $80-100 for cost-saving equipment if they are guaranteed to save 10-30% off of their monthly energy bill.[66] A recent study by the DOE reported that seven out of ten people expressed "high interest" in a unit that will keep them apprised of their energy use as well as dynamic pricing. More interesting is that one of the most popular iPhone applications (APPs) is an energy-savings APP. Clearly, customers are interested in various ways to manage their energy costs, or have a provider manage it for them. The HAN will bring a rich set of consumption information to customers and the possibility of participating in time-differentiated pricing plans and load response programs that will permit them to save on their electric bills.

HAN is defined as a network contained within a user's home that connects a person's digital devices from computers and peripheral devices to telephones, televisions, home security systems, "smart" appliances, and other digital devices that are wired into the network. Including a HAN module allows multiple in-home appliances to be interconnected, yet individually identified and controlled, potentially allowing the user to carry out the following functions:

- remote load control of in-home appliances;
- improved measurement, verification and dispatch of demand response directives; and
- feedback displays to consumers showing the consumption and cost associated with usage of various appliances.

These functions may be used in connection with third-party demand response programs, and the customer's efforts to reduce consumption. The implementation project is addressing the market rules and processes needed to allow for the timely and cost-effective implementation of HAN in ERCOT.

C. Meter Testing and Accuracy

During the Spring of 2010, customers in the Oncor service area raised questions regarding the accuracy of smart meters, and some customers expressed the view that there was a link between higher electric bills and the recent deployment of smart meters.

[66] Findings from Parks Associates' nationwide survey, *U.S. Household Energy Usage: Behaviors and Opportunities for Innovation*, Spring 2010

In response to these questions, the Commission decided to retain an independent third party to evaluate the accuracy of the meters being deployed.

The Commission engaged Navigant Consulting, LLC (Navigant) to evaluate the accuracy of the meters. On July 30, 2010, Navigant submitted to the Commission its report entitled, "Evaluation of Advanced Metering System (AMS) Deployment in Texas – Meter Accuracy Assessment" (Report).[67] Many of the issues investigated were in response to complaints filed with the Commission, as well as various media reports and inquiries, targeted at concerns over the accuracy of the meters currently being deployed in the three utility territories.

As part of the evaluation and investigation, Navigant directed the independent testing of the accuracy of a large sample of smart meters and a review of complaints received by the Commission from residential customers with smart meters who expressed concerns over their meters and/or increases in their electric bills. Navigant also performed an independent evaluation of the AMS being deployed by each of the TDUs, including an evaluation of the transfer of customer electric usage information from smart meters through the utility's infrastructure for verification of the utility's or meter-to-bill data flow.

The scope of work for the investigation included five major areas:

1. Independent testing of the accuracy of smart meters being deployed;
2. Investigation of customer meter and billing related complaints filed with the Commission relating to smart meters;
3. Analysis of the historical electricity usage of customers with smart meters versus customers who had yet to receive a smart meter;
4. Evaluation of smart meter testing, deployment and provisioning process and controls; and
5. Evaluation of the AMI, including the controls in place to ensure that electricity usage information is accurately communicated from the smart meter to the market for billing purposes.

Because AEP Texas had only recently begun its deployment of smart meters and was still in the process of readying its systems for use, Navigant's efforts with AEP Texas were limited primarily to the independent testing of a sample of smart meters and an evaluation of AEP Texas' meter testing, deployment and planned provisioning processes. The

[67] *Smart Meter Testing: Monitoring and Evaluation of Deployment of Advanced Meters*, Project No. 38053.

Commission provided oversight and direction of the independent investigation and evaluation conducted by Navigant.

During the course of the four-month long investigation, Navigant independently tested over 5,600 smart meters for accuracy and reviewed historical test results for accuracy on nearly 1.1 million smart meters and over 86,000 electromechanical meters. Navigant had full access to electronic records available from each TDU including records related to approximately 850,000 residential smart meters already deployed and up to four years of historical electric usage records for over 1.8 million residential customers with either a smart or electromechanical meter. Navigant reported that in total, it identified and analyzed approximately 345 million records in potentially relevant electronic files.

Navigant reported that, in its opinion, the vast majority of smart meters currently installed by Oncor, CenterPoint and AEP Texas are accurately measuring and recording electricity usage and communicating that information through the AMS for use in customer billing. Navigant noted, however, that the evaluation and investigation uncovered certain discrete groups of smart meters that were not performing at acceptable levels, and where a certain number of customers appeared to have been impacted. Further, Navigant stated that it was apparent that any potential impact to customers from the observed smart meter failures could have been limited, if not avoided entirely, if the respective TDU had effectively monitored and analyzed the performance of these smart meters using the information available to it.

The Navigant report concluded that smart meters and AMS are significantly more automated and complex than prior processes and systems involving electromechanical meters and manual meter readers. AMS still involves significant human interaction to identify, evaluate, analyze and process information related to the operations of the smart meters and related systems. Navigant reported that there is still a possibility of error and oversight with AMS. What is important, Navigant noted, is that in systems under development there are processes, procedures and controls that exist to quickly identify and address issues as they arise, and those challenges are addressed in new processes, procedures and controls implemented by the Texas TDUs to ensure that similar issues do not occur in the future.

IV. Benefits and Trends

A. Benefits for the Market

AMI creates savings and benefits for the customer, the utility, ERCOT and the REP. Benefits are realized with respect to increased efficiency, improved environment, reduced costs, remote disconnection and reconnection, remote outage detection and other power system problems, better information for power system planning, innovative product offerings and consumption management and control options. Some of the savings and benefits include:

- **Increased control of consumption and lower electric bills.** AMI provides new ways for customers to manage their energy usage. Customers in the Oncor, CenterPoint and AEP Texas territories with a smart meter installed, can register at www.SmartMeterTexas.com to view detailed consumption data for the previous day, down to 15 minute intervals, the previous month, or the past 13 months. With an IHD or HAN device in their homes, customers can view consumption in real time. Access to usage data enables the customer to better manage consumption and lower their monthly electric bills.
- **Utility operational savings.** Because meter readers will not have to go house to house to read meters and connect and disconnect service, utilities save labor and transportation costs. In addition, remote meter reading increases customer privacy. Utilities also incur savings through increased automation/accuracy of back office business processes.
- **Automatic outage notification.** Smart meters permit utilities to obtain information on power outages quickly, including the location of the problem and the customers who are not in service. This allows power to be restored more quickly and at less cost to the utility. Faster response time provides customers a higher level of service.
- **Faster transactions, better customer service.** Remote disconnection and reconnection of electric service decreases the time it takes to process service orders and reduces service fees. Switching REPs can also be accomplished more quickly.
- **Environmental benefits.** As customers choose to reduce or shift demand at peak times, the least efficient power plants are likely to operate less. The result is fewer emissions into our air. Fewer trucks on the road to process service orders also contribute to a cleaner environment.

- **Demand response and reliability.** AMI's two-way communication facilitates various demand response programs. This includes direct load control of a customer's smart appliances, which can be programmed to adjust usage in response to electric prices or when the operators of the power system face challenges in maintaining service.
- **Innovative product/price offerings.** REPs will be able to offer innovative products and services such as time-differentiated rates and HAN devices that allow customers to better understand and manage consumption.
- **Reduced costs from shifting load to off peak hours.** Shifting load to off peak hours through time-differentiated rates or appliance control programs may decrease demand for peaking power. This may lead to a lower clearing price for electricity that saves both the REP and the customer money. Shifting load to off peak hours may also obviate the need to build additional peaking power plants.
- **Prepayment capability.** Prepaid service through smart meters allows customers to prepay for service as needed rather than based on monthly bills. With this service, customers may be able to make several smaller payments over the course of a month and avoid paying costly deposits.
- **Meter tampering alert.** Smart meters signal the utility alerting them to the possibility of meter tampering or theft. These remote alerts allow the utility to investigate and resolve the problem quickly.

Smart Meter Benefits and Savings

Benefits and Savings Include:	**Customer**	**REP**	**Utility**	**ERCOT**
Increased Control of Consumption, Lower Electric Bills	**X**	**X**		
Utility Operational Savings (remote meter reading)	**X**		**X**	
Automatic Outage Notification	**X**	**X**	**X**	**X**
Faster Transactions, Better Customer Service (move-in/move-out, switching REPs)	**X**	**X**	**X**	
Environmental Savings	**X**			
Demand Response and Reliability	**X**	**X**	**X**	**X**
Innovative Product/Price Offerings (TOU & dynamic pricing rates, HAN devices)	**X**	**X**		
Shifting Load to Off Peak Hours	**X**	**X**	**X**	**X**
Prepayment Capability	**X**	**X**		
Meter Tampering Alert	**X**	**X**	**X**	

AMI's benefits to utilities are numerous. Reduction in meter reading costs has been the central reason offered in support of AMI deployment, particularly by integrated utilities that have these systems deployed. AMI also provides operational savings to the utility through increased automation, data collection, information management, and billing processes. This allows the utility to collect system-wide, consistent usage profile data to better appreciate the impact of loads on the reliability of transmission and distribution systems. The customer, the REP, and the utility should benefit from cost savings associated with the automated reading, data collection and billing process. Savings realized by the utility are used to offset the surcharge.

AMI has the potential to enhance competition in the retail electric market through innovative price offerings that were not feasible with conventional meter technology. Customers will be able to elect plans that enable them to shift demand at their discretion to times when the electricity price is lower. As deployment continues, customers will be able to enjoy better customer service, including flexible billing cycles designed to match customer preferences and may be able to switch REPs in a more timely fashion. Currently, customers with smart meters can request connection and disconnection of service to fit move-in/move-out schedules rather than scheduling a service call from a technician in the field.

AMI gives customers the flexibility to prepay for service as needed rather than through monthly bills. Prepaid programs would allow customers to pay for service in smaller increments and eliminate onerous deposits for customers with poor credit. In the future, participants enrolled in a prepaid service may be able to use the meter as a payment device depositing value in the meter through an in home display device that is also a card reader. Prepayment plans are made possible by the meter's ability to remotely disconnect and reconnect service, often within two hours.[68]

B. Industry Trends

1. Reliance on Demand Response

Demand response refers to the ability of customers to alter their normal consumption patterns in response to changes in the price of electricity or incentive payments designed to induce lower electricity use when prices are high or when system reliability is in jeopardy. Because electricity cannot be stored and has to be consumed instantly, and because generation plants of varying efficiency are used to meet demand, the price of

[68] *Nations Power Announces Prepaid Services and Real Time Pricing*, Smart Meters, Feb. 28, 2010, www.smartmeters.com.

power varies by time of day, day of the week, and season. Generally speaking, there are two types of demand response. Dispatchable demand response refers to planned changes to consumption that a customer agrees to make when directed to by a program operator. This includes direct load control (DLC) of customer's electrical equipment such as an air conditioner or water heater and larger scale interruptible load programs for commercial and industrial customers who agree to reduce demand when requested to do so. DLC programs have been in place for decades. Historically, DLC has been used almost entirely as a reliability resource by utilities. However, the use of DLC as an economic resource, operating in conjunction with price responsive demand is also expected to be available with smart meters. According to the FERC:

> The Smart Grid concept envisions a power system architecture that permits two-way communication between the grid and essentially all devices that connect to it, ultimately all the way down to large consumer appliances. … Once that is achieved, a significant proportion of electric load could become an important resource to the electric system, able to respond automatically to customer-selected price or dispatch signals delivered over the Smart Grid infrastructure without significant degradation of service quality. [69]

Nondispatchable demand response occurs when the customer is no longer a passive consumer but chooses whether and when to consume, based on a retail rate that changes over time. These time-differentiated pricing programs reflect the variable cost of electricity and charge higher prices during peak demand hours and lower prices for other hours of the year.[70] The National Assessment of Demand Response Potential, released by the FERC in June 2009, found that the existing operational demand response programs in the United States have the capacity to offset 4% of current U.S. peak demand.[71] Most of the demand response programs operating today are driven by reliability concerns and involve either direct load control of residential loads or interruptible rates for large commercial and industrial customers. Nationwide, there is substantial geographic variation in the amount of demand response programs offered. If the current level of demand response were to expand to include areas with little or no demand response and customer participation were to reach levels representing today's best industry practices, the capacity to offset U.S. peak demand could rise to 9%.

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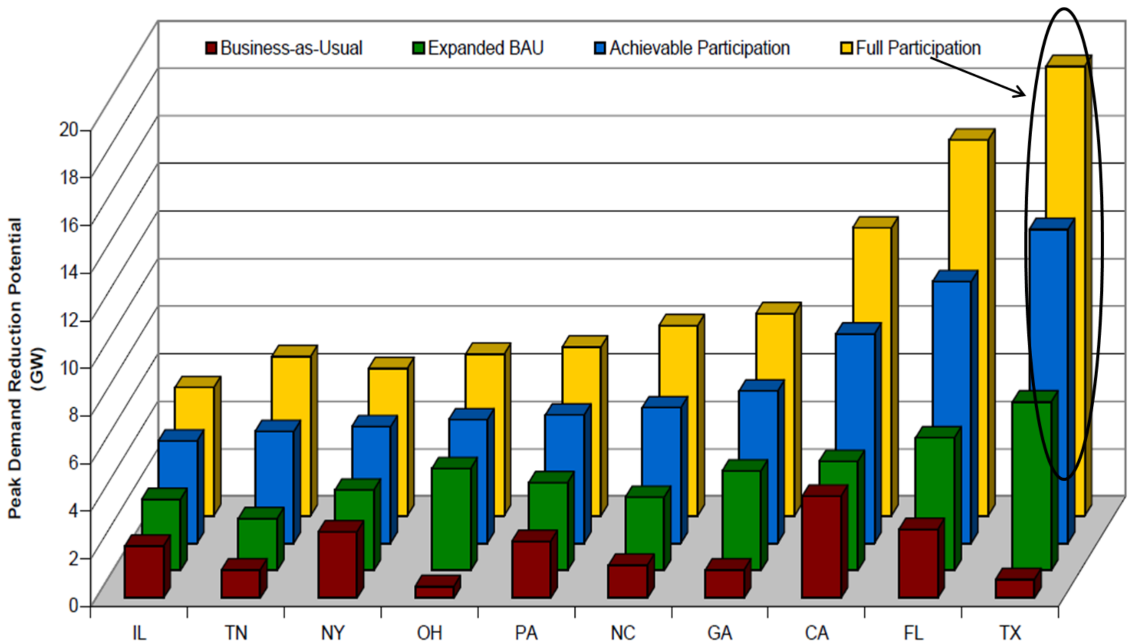
[69] Smart Grid Policy, 126 FERC ¶ 61,253, at P19 and n.23 (2009).
[70] *National Action Plan on Demand Response*, The Federal Energy Regulatory Commission Staff, Docket no. AD09-10, June 17, 2010.
[71] *A National Assessment of Demand Response Potential Staff Report*, Federal Energy Regulatory Commission, June 2009.

The FERC assessment found that price driven demand response such as dynamic pricing enabled by the deployment of AMI, holds the greatest potential for peak load reductions. However, dynamic pricing has very little market penetration today. In 35 of the 50 states, dynamic pricing currently has no impact. In the remainder of the states, the impact is minimal. Depending on how dynamic pricing is deployed, peak demand could be offset by 14 to 20 percent. Texas was identified as having the most potential for demand response as shown in the chart below.

FERC Estimates >18 GW of Demand Response Potential in Texas by 2019



Source: *FERC National Assessment of Demand Response*, page 42

Currently, Texas has very little demand response in place. Most of the demand response is motivated by system reliability concerns and comes from the large commercial and industrial sector. Existing demand response includes interruptible tariffs and other demand response programs available in the ERCOT market. DLC in the residential and small commercial sectors represents a very small portion of Texas's demand response. Demand response programs that rely on dynamic pricing or TOU rates are only just beginning to be offered in Texas.

Currently, one REP in Texas, Nations Power, offers prepaid service with real time pricing. 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 real time pricing. Customers have visibility to both their consumption and prices. By deciding to use less energy during the high priced peak hours, customers save money.[72]

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. This lower rate applies to 90% of the hours of the year.[73]

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.[74]

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.

Prepaid products can help customers conserve electricity as well. Direct Energy announced in July that it launched a 'pay-as-you-go' electricity service for Texans with smart meters, beginning in the Dallas metro area. The program is designed so that customers can avoid paying a deposit, pay for electricity as frequently as they wish, enjoy no contract term, and the flexibility to pay for more electricity when it meets their needs. Customers will be charged for their actual metered usage as determined by the smart meters. They will be kept up to date daily on how much electricity they have used, how much they are spending and how much money they have left in their account.

"This is a huge step-change for consumers, who now have the power to choose an easier way to pay, without a credit check or being tied to a long-term contract that may carry a penalty. We're beginning in Dallas and as more people across Texas have a 'smart' meter

[72] Information provided to Commission Staff by Nations Power, July 2010.
[73] Information provided to Commission Staff by TXU Energy, July 2010.
[74] Reliant's TOU plan is made possible by the capability of smart meters to record electricity use for each 15 minute period of the day, www.reliant.com.

installed in their home we will be offering this service to them. We believe many people will find it a better way to buy and pay for their electricity" said Steven Murray, president of Direct Energy Residential.

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]

Texas has much to gain from increasing participation in demand response programs. Benefits to utilities, ERCOT and customers include reducing the need for expensive peaking capacity, improving system reliability and lowering power costs. REPs also have much to gain as they embrace demand response programs that can offer both competitive pricing and products to their customers and reduced exposure to price uncertainty, because they can match their purchases in the wholesale market to their customers' demand with greater accuracy.

Texas leads the nation in energy consumption. In 2008, Texas's system peak demand was 72,723 MW[76] far exceeding system peak demand in any other state.[77] California was a distant second followed by Florida. This high system peak demand is due in large part to the State's robust industrial sector, high population and higher than average residential central air conditioning usage. Texas is, however, uniquely positioned to increase demand response. The key drivers of the potential in Texas include the fact that very little demand response currently exists; the State has a higher than average saturation of residential air conditioning and AMI deployment leads the national average.

2. Infrastructure Investment

Evidence of the nation's economic downturn that began in late 2007 was still visible in the energy markets in 2009. Total electrical generation dropped by 1% in 2008 followed

[75] *Gateway Energy Services Conducting Time of Use Pilot at Oncor*, Energy Choice Matters, 5 (July 15, 2010).
[76] In the ERCOT region, peak demand was 62,174 MW in 2008 and 63,400 MW in 2009, and the record was broken four times in August 2010 to reach 65,776 MW, all time high. *Electric Reliability Council of Texas, 2009 Annual Report*, July 15, 2010, p. 18 and *ERCOT Press Release*, August 23, 2010, http://www.ercot.com/news/press_releases/2010/nr-08-23-10.
[77] *A National Assessment of Demand Response Potential Staff Report*, Federal Energy Regulatory Commission, June 2009.

by a drop of 3% in 2009. Although other factors such as mild weather contributed to this decrease, it was the first time in 60 years since the U.S. Energy Information Administration (EIA) began tracking this data that electricity use fell in two consecutive years.[78] Texas fared better than the rest of the Nation. In 2008, electricity use increased by 1.7% and dropped only 1.3% in 2009.[79] History shows, however, that in the short term demand for electricity fluctuates in response to business cycles and weather. That said, the EIA expects demand for electricity to grow by an average of 1% per year through 2035 in response to both projected economic and population growth. ERCOT expects economic recovery in Texas to result in a 1% growth in demand in the short term rising to 3% around 2012 or 2013.

Demand for electricity continues to increase in Texas as economic development and continued population growth spurs growth in the Texas economy. Because growth in demand for all types of energy is on an upward trend, some analysts believe that the energy industry needs to prepare for a period of much higher capital expenditures.[80] This results from a confluence of factors:

- Shrinking generation reserve margins, as the glut of surplus capacity from earlier in the decade decreases;
- Increased spending on pollution controls, especially to comply with nitrogen-oxide, sulfur, and mercury requirements;
- The perception that the federal government will enact carbon legislation;
- The need to replace aging transmission and distribution infrastructure, much of which was put in place 30-40 years ago and is nearing the end of its design life;
- Continued robust rates of population growth and economic growth in many parts of the United States, resulting in the need for system expansion; and
- Technology spending on areas such as customer information systems and AMI and smart grid technologies.

To account for higher capital expenditures, utilities in Texas have requested rate increases. Since March of 2009, six rate increase requests have been approved by the Commission, and four are currently pending. Entergy received a $46.7 Million increase in March 2009; Oncor Electric Delivery received a $115.1 Million increase in November of 2009; Texas New Mexico Power (TNMP) received a $6.8 Million increase in August 2009; Southwest Public Service (SPS) received a $57.4 Million rate increase in June 2009; Southwestern Electric Power Company (SWEPCO) received a $25 Million rate

78 *Annual Energy Outlook 2010*, U.S. Energy Information Administration, pp. 2, 65.
79 Electric Reliability Council of Texas, 2009 Annual Report, July 15, 2010, p. 18.
80 Roger Wood, *Banking on the Big Build*, Public Utilities Fortnightly, 49 (October 2007) and cited with approval in National Regulatory Research Institute report *Private Equity Buyouts of Public Utilities: Preparation for Regulators*, December 2007 by Stephan G. Hill at p. 36.

increase in April 2010[81]; and El Paso Electric Company (EPEC) received a $17.2 Million increase in July 2010. Four additional cases are pending before the Commission: parties in the Entergy rate case filed a stipulation (with a $59 million increase and an additional $9 million increase starting in May 2011)[82], and CenterPoint Houston Electric (CEHE), SPS and TNMP all have rate increase requests pending. The nation's infrastructure investment needs are at an all time high. It is estimated that $1.5 trillion will be required between 2010 and 2030. The estimated cost breakout is as follows:

- Distribution - $582 billion
- Transmission - $298 billion
- AMI, Energy Efficiency and Demand Response - $85 billion
- Generation - $505 billion if there are no changes in carbon policy. [83]

To ensure reliability and competitive functioning of the electricity market, Texas must rely upon an integrated approach that combines the traditional solutions of making infrastructure investments in new transmission and generation facilities with demand response solutions made possible by the deployment of AMI infrastructure that give customers the ability to better understand and control their usage. Demand response programs have the potential to permit customers' needs to be met with lower levels of investment in generation, transmission and distribution facilities. As customers choose to participate in demand response programs that reduce usage during periods of high demand and prices, fewer additions to generation, transmission and related facilities will be required than would otherwise in the absence of such a program. Besides reducing peak demand, demand response programs such as dynamic pricing provide a substantial benefit that as demand for expensive peaking energy declines, so does the price. This benefits not only the customers who choose to participate but also those who do not.

3. Deployment Outside of Texas and Successful Pilots and Programs

The scope of smart metering deployment across the country has increased over the last year. Federal and state initiatives have aided in accelerating meter deployment and developing comprehensive smart grid policy. FERC approved a policy statement

[81] $25 Million total increase, $10 of which is a 1-year surcharge.
[82] This stipulation was filed by parties in August 2010.
[83] *U.S. Transmission Investment: Policies and Prospects*, Peter Fox-Penner, The Brattle Group, April 28, 2009 and cited with approval in "Transforming America's Power Industry: The Investment Challenge 2010-2030" prepared for the Edison Financial Conference, November 10, 2008 by Marc Chupka et al.

regarding the deployment of smart grid July 16, 2009.[84] The smart grid policy looks to create industry standards to:

- Ensure the cyber-security of the grid
- Provide two-way communications among regional market operators, utilities, service providers and consumers
- Ensure that power system operators have equipment that lets them run reliably by monitoring their own systems and neighboring systems that affect them
- Coordinate the integration into the power system of emerging technologies such as renewable resources, demand response resources, power storage facilities and electric transportation systems.[85]

DOE funding for smart grid made possible by ARRA, will have an impact on AMS investment of over $8 billion in the next few years when matched by the required private utility funds.[86] It is estimated the DOE SGIG grants have created or saved 1,209 jobs related to smart grid, not including the jobs created through private investment.[87] Additional AMS workforce was created through $100 million in ARRA stimulus designated for training 30,000 workers in various smart grid technologies.[88]

Individual states have also pushed for smart metering and smart grid implementation. In October 2009, the California legislature adopted SB 17 requiring the state Public Utility Commission develop a set of requirements for smart grid deployment to include improved efficiency, reliability and cost-effectiveness of system operations, planning and maintenance.[89] Additionally, all public utilities with over 100,000 metered customers must develop and submit their own deployment plan by July 1, 2011; smaller utilities can submit plans, but are not required to do so.[90] The bill is the first of its kind in the US to develop a coordinated process for AMS deployment; several other states including Maine, New York, Ohio and Pennsylvania have adopted similar legislation.

[84] 128 FERC ¶ 61,060 United States of America Federal Energy Regulatory Commission 18 CFR Chapter 1 [Docket No. PL09-4-000] Smart Grid Policy (Issued July 16, 2009).
[85] *FERC makes smart grid policy official*, Smart Grid Today, (2009, July 17), available at http://www.smartgridtoday.com/members/514print.cfm.
[86] *Follow the Money: Stimulus Funding Begins to Flow into the Smart Gird Sector*, KEMA Automation Insight, (2010, February), available at http://www.kema.com/services/consulting/utility-future/smart-grid/follow-the-money-stimulus-funding-begins-to-flow-into-smart-grid-section.aspx.
[87] *SGIG winners tell DOE 1,209 jobs created or saved this year*, Smart Grid Today, (2010, August 5), available at http://www.smartgridtoday.com/members/1893.cfm.
[88] *Ibid*.
[89] California SB 17 Chapter 327, an act to add to Chapter 4 (commencing with Section 8360) to Division 4.1 of the Public Utilities code, relating to electricity [Approved by Governor and filed October 11, 2009].
[90] *Ibid*.

The Edison Foundation estimates by 2019, approximately 59,940,150 U.S. households will be equipped with a smart meter, accounting for 47% of total households.[91] Including current proposals for AMS deployment, twenty-three states will have 50% or greater smart meter market penetration during the same time frame. See Appendix E for a description of selected projects currently deploying large-scale AMS.

A recent report by the American Council for an Energy-Efficient Economy (ACEEE) says smart meters alone are not enough. Consumers could cut their electricity use as much as 12% and save at least $35 billion over the next 20 years thus making a meaningful contribution to U.S. energy security and climate goals if utilities employ energy-use feedback tools to get consumers more involved in the process of using less energy. The report estimated that this year the typical U.S. household will spend about $1,500 for the electricity and natural gas, likely using 20% to 30% more energy than needed. The report based on a review of 57 different residential sector feedback initiatives performed between 1974 and 2010, concludes that to realize potential feedback-induced savings, smart meters must be used in conjunction with real-time (or near-real time) web-based or in-home devices and enhanced billing approaches and well-designed programs that successfully inform, engage, empower, and motivate customers.[92] Numerous studies continue to demonstrate DR varies from modest to substantial, largely depending on the data used in the experiments and the availability of enabling technologies. Across the range of experiments studied, TOU rates induced a drop in peak demand that ranged between 3 to six 6% and CPP tariffs led to a drop in peak demand of 13 to 20%. When enabling technologies were used, the latter set of tariffs lead to a drop in peak demand in the 27 to 44% range.[93]

These reports come as a growing number of utilities are launching smart meter pilots in efforts to test customer response to dynamic pricing. Substantial evidence accumulated over the past decade through numerous well-designed experiments indicates that, regardless of geographic differences, customers respond to dynamic prices. When equipped with visual aid such as a HAN device, which reminds them when high prices are in effect, customers tend to respond more. When customers have enabling

[91] *Utility-Scale Smart Meter Deployments, Plans & Proposals*, Institute for Energy Efficiency, (2010, February), available at http://www.edisonfoundation.net/iee/issueBriefs/IEE_SmartMeterRollouts_update.pdf.
[92] Ehrhardt-Martinez, Karen, Kat A. Donelly and John A. "Skip" Laitner, *Advanced Metering Initiatives and Residential Feedback Programs: A Meta-Review for Household Electricity-Saving Opportunities*, June 2010, available at http://www.aceee.org/pubs/e105.htm.
[93] Faruqui, Ahmad and Sanem Sergici, *Household Response to Dynamic Pricing of Electricity — A Survey of the Experimental Evidence*, January 10, 2009, available at http://www.hks.harvard.edu/hepg/Papers/2009/The%20Power%20of%20Experimentation%20_01-11-09_.pdf.

technologies, they respond more than with no technology.[94] A few pilots are described below.

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 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%.[95]

Pepco/PowerCentsDC

Potomac Electric Power Company (Pepco), the regulated electric utility serving 750,000 customers in Washington D.C. and parts of Maryland, completed their yearlong integrated AMS pilot program in February 2009. Starting in July 2008, approximately 900 Pepco customers volunteered to receive a smart meter, and be placed on one of the three test rate plans based on hourly pricing (HP), critical peak pricing (CPP) or a critical peak rebate (CPR) incentive.[96] Additionally, the participants with central air conditioning received a smart thermostat equipped to respond to price signals; all participants received an introductory packet with education materials and a detailed personal "Electric Usage Report" in their monthly billing statement.[97]

With HP, pilot participants reduced their peak demand usage by 4% in both the summer and winter intervals. Participants on the CPP plan were able to reduce peak electric demand 25% in summer and 10% in winter, the largest demand savings of the group. The final rate group, those under the CPR plan, reduced peak demand 11% in the summer

[94] 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.
[95] 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.
[96] *PowerCentsDC Program Interim Report*, eMeter Strategic Consulting for the Smart Meter Pilot Program, Inc. (2009, November), available at http://www.powercentsdc.org/ESC%2009-11-02%20PCDC%20Interim%20Report%20FINAL.pdf.
[97] *Ibid*.

interval (winter data not statistically valid). Overall, PowerCentsDC participants reduced their electric bill on average 7.8% over the test group during the pilot program.

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.[98] 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 PTP rate plan reduced peak demand by 23.3% if supplied with an efficiency enabling device, and 16.1% without. 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.

[98] 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/Plan-it%20Wise%20Pilot%20Results.pdf.

[99] *Ibid*.

IV. Conclusion & Recommendations

The Commission believes that the deployment of AMI is a critical component of the evolving Texas electric market. As deployment occurs, it can enable market-based demand response, help the market to mature, yield savings for utilities, and create efficiencies in market processes for REPs and ERCOT.

Most importantly, AMI can enhance service quality to retail customers in several areas:

- expediting connection and disconnection of service;
- providing a prepayment option that will reduce deposit requirements;
- giving customers the tools to help manage energy costs
- enabling quicker service restoration following an outage; and
- helping balance the dynamics of supply and demand.[100]

The Commission offers the following recommendation for consideration by the Texas Legislature:

- The legislature should clarify whether the 2005 legislation relating to advanced meters, PURA §39.107, applies to utilities outside of ERCOT.[101]

[100] In times when reserve margins are tight, having customers who can reduce usage at peak times adds additional security to the system. For instance, under an energy-only market, spot electricity prices in ERCOT markets can increase sharply, reaching over $1,000 per MWh when almost all available generation is being deployed to meet "super peak" demand. These high prices would signal to retail customers that ERCOT has very little available generation to maintain system reliability, and could prompt customers that have the flexibility, such as customers running oil and gas pumping jacks, commercial freezers, and residential water heaters, to voluntarily reduce their energy use. Large retail customers participate in operating reserve markets today, through voluntary curtailments, and the Commission and ERCOT are exploring additional opportunities for loads to provide reserves to assist ERCOT in maintaining system reliability. Enhancing the opportunities for demand response can provide improved levels of reliability for customers who do not participate in the programs and financial benefits for customers who do.

[101] *See* P.U.C. SUBST. R. 25.130(b), which states, "This section is applicable to all electric utilities, including transmission and distribution utilities, other than an electric utility that, pursuant to Public Utility Regulatory Act (PURA) §39.452(d)(1), is not subject to PURA §39.107; and to the Electric Reliability Council of Texas (ERCOT).

Appendices

Appendix A Glossary for the Report

Advanced Metering Infrastructure or System (AMS/AMI): A system, including the associated hardware, software, associated system and data management. Includes the programming, communications devices that collect time-differentiated energy usage from advanced meters. The system collects, processes, and records the information, and makes the information available to REPs, ERCOT, customers, and the utility.

Automated Meter Reading (AMR): Automatic or automated meter reading allows a meter read to be collected without actually viewing or touching the meter with any other equipment. One of the most prevalent examples of AMR is mobile radio frequency whereby the meter reader drives by the property, and equipment in the vehicle receives a signal sent from a communication device under the glass of the meter.

Conservation: Conservation includes consumer actions or decisions to use less energy, perhaps by reconsidering priorities and eliminating some energy use. Actions could include turning off extra lights, raising thermostats a few degrees in the summer or lowering them in the winter, and taking pre-vacation steps such as turning off power strips or lowering water-heater temperatures.

Critical Peak Pricing (CPP): CPP rates are a hybrid of the time-of-use (TOU) and real-time pricing design. The basic rate structure is TOU. However, provision is made for replacing the normal peak price with a much higher CPP event price under specified trigger conditions (e.g., when system reliability is compromised or supply prices are very high).

Demand: Represents the requirements of a customer or area at a particular moment in time. Typically calculated as the average requirement over a period of several minutes to an hour, and thus usually expressed in kilowatts or megawatts rather than kilowatt-hours or megawatt-hours. Demand and load are used interchangeably when referring to energy requirements for a given customer or area.

Demand Response: The planning, implementation, and monitoring of activities designed to encourage customers to modify patterns of electricity usage, including the timing and level of electricity demand. Demand response covers the complete range of load-shape objectives and customer objectives, including strategic conservation, time-based rates, peak load reduction, as well as customer management of energy bills.

Demand Response Event: A period of time identified by the demand response program sponsor when it is seeking reduced energy consumption and/or load from customers participating in the program. Depending on the type of program and event (economic or emergency), customers are expected to respond or decide whether to respond to the call for reduced load and energy usage. The program sponsor generally will notify the customer of the demand response event before the event begins, and when the event ends.

Demand Response Load: The load reduction that results from demand-response activities.

Direct Load Control (DLC): A demand response activity by which the program operator remotely shuts down or cycles customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers.

Fixed Network: A fixed network refers to either a communication infrastructure which allows the utility to communicate with meters without visiting or driving by the meter location.

Home Area Network (HAN): Network contained within a user's home that connects a person's digital devices, from multiple computers and their peripheral devices to telephones, VCRs and DVD players, televisions, video games, home security systems, "smart" appliances, fax machines and other digital devices that are wired into the network.

Interval Data: Interval data is a fine-grained record of energy consumption, with readings made at regular intervals throughout the day, every day. Interval data is collected by an interval meter, which, at the end of every interval period, records how much energy was used in the previous interval period.

Interval Data Collection: For purposes including load research, demand response and on-demand reads, meter data is frequently collected in hourly or even 15-minute intervals. Short-term storage of this interval data takes place before the system communicates the data to the utility. In general, interval data can be collected at the meter, or at an intermediary spot such as the fixed network collector unit that reads the meter's output. Finer resolution of data in smaller time increments requires communications systems that can transmit the data without bogging down.

Load (Electric): The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Load Management: Demand management practices directed at reducing the maximum kilowatt demand on an electric system and/or modifying the coincident peak demand of one or more classes of services to better meet the utility system capability for a given hour, day, week, season, or year.

North American Electric Reliability Corporation (NERC): The organization certified by the Federal Energy Regulatory Commission (FERC) as the reliability organization for the nation's bulk power grid. NERC consists of eight Regional Reliability Councils in the lower 48 states. The members of these Councils are from all segments of the electricity supply industry - investor-owned, federal, rural electric cooperative, state/municipal, and provincial utilities, independent power producers, and power marketers.

Open Standards: An agreed-upon method or implementation defining how part of a process, product, or solution should operate. An open standard is made available so that any interested party or organization may provide part of an open system.

Power Line Carrier (PLC): Communication of meter data and other utility system data through power lines. PLC technology can be part of two-way systems.

Remote Connect/Disconnect: Disconnecting and reconnecting a customer's electrical service without accessing the customer's premises or sending a service vehicle into the field. A hard disconnect, that is, cutting off power to a premise by throwing a physical switch can be performed remotely, but requires additional specialized equipment at the meter. A virtual disconnect, that is, obtaining an on-demand meter read at the time a premise is vacated or occupied can be performed remotely through fixed network AMR systems. Virtual disconnect can also include monitoring of any consumption that should not be occurring after disconnect. In addition, some utilities are effectively utilizing mobile AMR systems to perform off-cycle, final reads associated with move-ins and move-outs.

Real Time Pricing (RTP): A retail rate in which the price for electricity typically fluctuates hourly reflecting changes in the wholesale price of electricity. RTP prices are typically known to customers on a day-ahead or hour-ahead basis.

Smart Grid: Real-time visualization technologies on the transmission level and smart meter and communications technologies on the distribution level that enable demand response, distributed energy systems (generation, storage, thermal), consumer energy management systems, distributed automation systems and smart appliances.

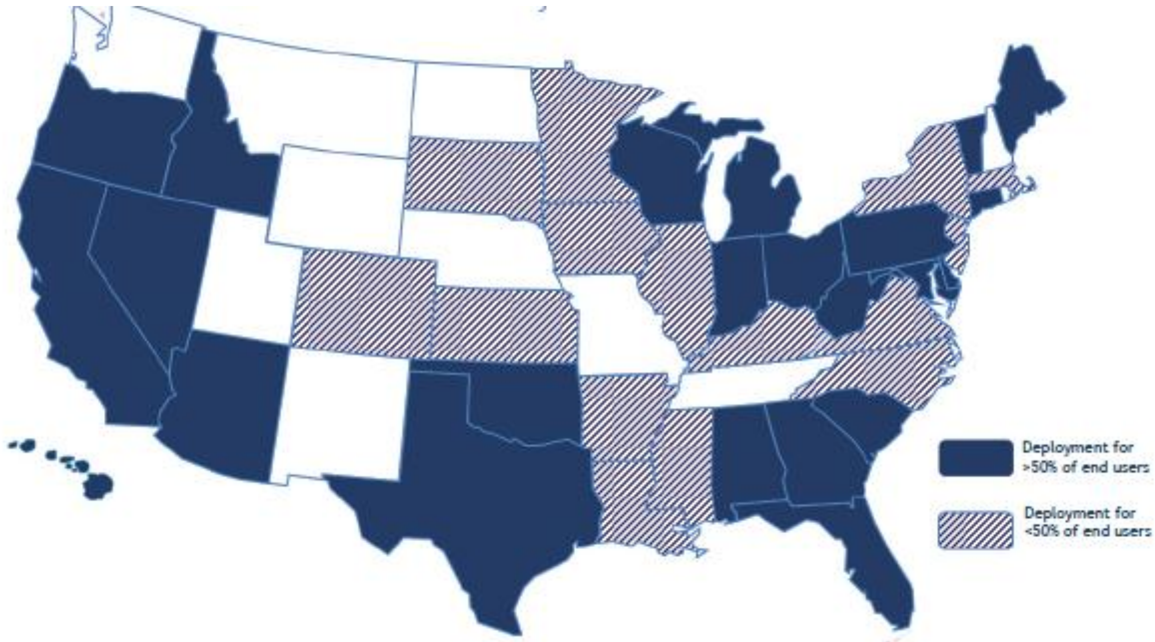
Smart Metering: See definition for Advanced Metering.

Smart Thermostat: Thermostats that adjust room temperatures automatically in response to price changes or remote signals from retail electric providers, utilities, authorized third-parties, and system operators. Also known as programmable, communicating thermostats.

Time Based Rate: A retail rate structure in which customers are charged different prices for different times during the day. Examples are time-of-use (TOU) rates, real time pricing (RTP), hourly pricing, and critical peak pricing (CPP).

Time of Use Rate (TOU): A rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. Daily pricing blocks might include an on-peak, partial-peak, and off-peak price for non-holiday weekdays, with the on-peak price as the highest price, and the off-peak price as the lowest price.

Appendix B Advanced Meter Deployments, Plans and Proposals



Source: Edison Foundation's Institute for Electric Efficiency 2010[102]

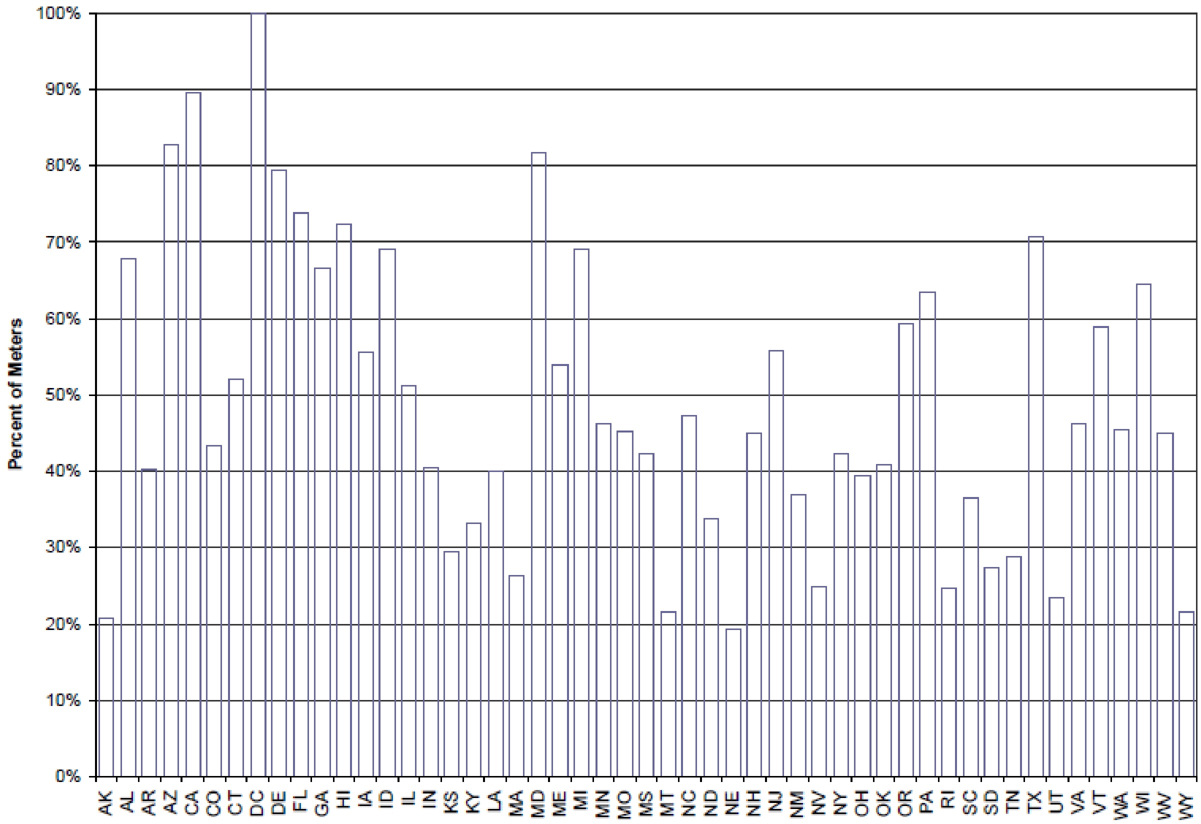
[102] This map summarizes smart meter deployments, planned deployments, and proposals by investor-owned utilities and some public power utilities as of February 2010.

Appendix C Utility Planned and Proposed AMI Deployment Projects

State	Utility	Number of Meters	Deployment Plan
AZ	AZ Public Service	0.8 million	Expected completion by 2012
AZ	Salt River Project	0.3 million	Completed in 2008
CA	SCE	5.3 million	Expected completion by 2012
CA	PG&E	5.1 million	Expected completion by 2012
CA	SDG&E	1.4 million	Expected completion by 2011
CT	Connecticut Light & Power	1.2 million	Deployment will start after the completion of a pilot program in 2009
DC (also in DE, MD, NJ, VA)	PEPCO Holdings	1.9 million	Target completion date is 2013. 258,000 deployed as of January 2009
FL	FPL	4.4 million	Completion date has not been released
GA (also in AL, FL, MS)	Southern Company	4.3 million	Expected completion by 2013
HI	HECO	0.43 million	Expected completion by 2015
IA (also in MN, WI)	Alliant Energy	1.0 million	Expected completion by 2011
ID	Idaho Power	0.47 million	Expected completion by 2011
IL	Ameren	1.1 million	Completion date unknown. 0.55 million meters installed as of June 2008
IL	Commonwealth Edison	0.2 million	Completion date has not been released
IN (also in KY, MI, OH, OK, TX, VA, WV)	AEP	5 million	Expected completion by 2015. One million of these meters are expected to be deployed by 2010
IN (also in SC)	Duke Energy	1.6 million	Filed in 2008, approval pending
MA	Statewide program	Potentially 2.6 million	MA Green Communities Act mandates a smart meter pilot, potentially followed by a statewide deployment
MD (also in PA, WV)	Allegheny Power	Potentially 0.7 million	Expected filing August 2009
MD	Baltimore Gas & Electric	1.2 million	Completion date has not been released
ME	Bangor Hydro-Electric	0.12 million	Expected completion by 2010
MI	DTE	4.0 million	Expected completion by 2014
OR	Portland General	0.85 million	Expected completion by 2010
PA	Statewide program	6 million	Act 129 signed in 2008 mandates that all customers must have smart meters by 2018
TX	Oncor	3 million	Expected completion by 2012
TX	CenterPoint	2 million	Expected completion by mid-2012
TX	Austin Energy	0.23 million	Approved in 2008
VA	Dominion	0.2 million	Deployment for the pilot to begin in 2009
VT	Central VT Public Service	0.15 million	Expected to begin between 2011-2013

Source: Edison Foundation's Institute for Electric Efficiency 2009

Appendix D Advanced Metering Penetration by State in 2019



Source: Federal Energy Regulatory Commission, 2009

Appendix E Advanced Metering Deployment inside the U.S.

Florida Power & Light Group (FPL), serving 4.4 million customers across the state of Florida, is working towards full smart meter deployment in their service territory by 2013. FPL was the recipient of a full $200 million SGIG grant through the DOE with funds designated towards smart meter, devices and monitoring equipment deployment.[103] At the heart of the FPL project is "Energy Smart Miami", a model smart grid city with over 1 million smart meters paired with technologies including solar generation and smart appliances.[104] The project will utilize an open network system allowing independent developers to create applications for the smart meters that in the future, consumers could use for energy efficiency and monitoring.[105]

PECO Energy Company's smart meter deployment plans also benefited from the maximum $200 million SGIG grant.[106] The Southeastern Pennsylvania utility serves 1.6 million metered electric customers and plans to use the funds to deploy 600,000 smart meters, communication systems and AMI by 2012.[107] Provisions in the deployment also provide support for low-income customers and smart-grid related job training.[108] Within 10 years, the project scope will be expanded to provide meters to PECO's entire territory. PECO president and CEO Denis O'Brien foresees "a day coming soon in which customers can get real-time information about how they use energy and energy costs, They will be able to remotely control appliances, save money and help the environment. [PECO envisions] a more modern, highly reliable energy delivery system that will not only keep the lights on, but better accommodate electric vehicles, energy storage facilities, and renewable energy".[109]

Southern California Edison (SCE) began deployment in June 2009 of one of the most ambitious smart meter deployments in the nation. The $1.3 billion deployment plan will install 5.3 million smart meters in eleven California counties by 2012.[110] SCE's meter deployments are part of their SmartConnect program designed to reduce consumption in population dense territory by 1,000 MW upon completion.[111] SmartConnect will make a PTR rate plan available to customers to encourage peak demand reduction. Smart grid

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[103] Florida Power & Light Company Smart Grid Project, available at http://www.smartgrid.gov/project/florida-power-light-company-smart-grid-project.
[104] *Miami slated to see biggest US smart grid rollout to date*, Smart Grid Today (2099, April 21), available at http:///www.smartgridtoday.com/public/183.
[105] *Ibid*.
[106] PECO Energy Company Smart Grid Project, available at .http://www.smartgrid.gov/project/peco-energy-company-smart-grid-project.
[107] *PECO Announces Plans for Advanced Smart Grid*, Select Greater Philadelphia Newsletter (2009, September), available at http://www.selectgreaterphiladelphia.com/news/newsletter/2009/9/PECO.htm.
[108] *Ibid*.
[109] *Ibid*.
[110] Southern California Edison backgrounder | Edison's Smarter Meter, available at http://www.sce.com/NR/rdonlyres/4BDCBE35-697E-49C6-9773-C49A019E6FD3/0/SCEsSmarterMeter.pdf.
[111] *Ibid*.

initiatives will continue to be one of the utilities main investment areas for the next twenty years.

Portland General Electric (PGE) has been deploying smart meters since 2008 and will continue with full deployment throughout the end of 2010. In total, PGE will install approximately 800,000 smart meters to residential and C&I customers in their northern Oregon territory.[112] Once deployed, PGE looks to utilize AMS to develop demand response and dynamic pricing as means to encourage peak load reduction. Customers will benefit from an online portal designed to provide consumption information and energy efficiency advice.[113] They will also have the ability due to the meters remote read capabilities to pick their preferred billing date. PGE estimates full deployment will eliminate 1.2 million miles driven by meter-readers, reducing 1.5 million pounds of CO_2 emitted per year.[114] Total savings to consumers should be at least $34 million over the next 20 years.

Salt River Project (SRP), an Arizona municipal utility, has recently expanded the smart meter initiative they originally started in 2003.[115] SRP will deploy an additional 500,000 meters starting in 2010, for a total of approximately 940,000 smart meters installed in the service territory. Benefiting from a SGIG grant funding 49.9% of the $114,003,719 deployment, SRP will also use the funds to upgrade the customer web portal and initiate new dynamic pricing plans. As an early adopter of smart metering technology, SRP will expand on the AMS enabled rate structures they have currently deployed. Over 84,000 customers already participate in SRP's prepaid service plan, the largest of enrollment of any utility in North America.[116] By pairing a prepay plan with an energy monitoring device, participants reduce consumption by 12% on average. Additionally, SRP has the third-largest TOU enrollment of any utility with 222,000 participants. Under a TOU plan, customers achieve an average 7% lower electric bill.[117] With the additional meter deployments, SRP can further distinguish themselves as a leader in dynamic pricing.

Upper Midwest based **Alliant Energy Corporation** began deploying smart meters to their Wisconsin territories in 2008. Alliant will begin smart meter deployment in Iowa and Minnesota, the rest of their service territory, in 2010.[118] Overall, the utility will install a full

[112] *PGE moves forward on smart meter installation territory-wide*, Portland General Electric (2009, April 14), available at http://www.portlandgeneral.com/our_company/news_issues/news/04_15_2009_pge_moves_forward_on_smart_me.aspx.
[113] *Ibid*.
[114] Smart Meters for Homes | PGE, available at http://www.portlandgeneral.com/SmartMeter/residential.aspx.
[115] *SRP to double Elster EnergyAxis AMI Smart Grid solution deployment*, SRP Media Advisory, (2010, May 18), available at http://www.srpnet.com/newsroom/releases/051810.aspx.
[116] SRP 2009 Annual Report, Letter from the General Manager, available at http://www.srpnet.com/about/financial/2009annualreport/GMLetter.aspx.
[117] *Ibid*.
[118] *Utility-Scale Smart Meter Deployments, Plans & Proposals*, Institute for Energy Efficiency (2010, February), available at http://www.edisonfoundation.net/iee/issueBriefs/IEE_SmartMeterRollouts_update.pdf.

AMS deployment to their one million metered electric customers as the foundation of their smart grid efforts.[119] In addition to energy management and efficiency savings, customers will possibly see long term financial benefits from smart grids ability to prolong the lifespan of aging utility infrastructure.[120] Alliant envisions smart metering as the stepping stone for distributed generation interconnection and plug-in electric vehicles. TOU pricing is already available throughout Alliant's territory; those customers without a smart meter can request accelerated deployment to their site if they agree to enroll in the plan for one year.[121]

[119] Alliant Energy | Smart Grid, available at http://www.aliantenergy.com/ami.
[120] *Ibid*.
[121] Alliant Energy | Time of Day Pricing, available at http://www.alliantenergy.com/UtilityServices/ForYourHome/014650.

Appendix F Advanced Metering Deployment outside the U.S.

In **Italy**, the regulator AEEG mandated full introduction of smart meters to all 36 million low-voltage consumers over the period 2008 to 2011. This followed the world's first large-scale $3 billion rollout of 27 million smart meters across Italy by the largest utility Enel from 2001 to 2006 (currently 32 million).[122] Enel customers can currently read their energy consumption, rates and contract on the meter display. The utility estimates that smart meters allowed to reduce service interruption per customer from 128 to 49 minutes per year, and the related costs for distribution system operators decreased from €80 to €49 per customer per year.[123] With annual savings of $750 million, Enel anticipates recovering the AMI investment within 4 years.[124] With more than 90% of smart meters installed, Italy is among the countries with the highest penetration of advanced meters.[125]

Sweden was among the first of the European countries to conduct pilot projects in 2001 and became the first to install smart meters for all its customers in 2009, mandated by government regulation.[126] The implementation of smart meters is based on the law passed in 2003 that requires mandatory hourly electricity metering from July 2009.

In **Finland**, around 50% of the 5.3 million people have smart meters installed. The government mandated that all households be equipped with hourly read smart meters by 2013. Several new innovative services will become available, including the freedom for villages, districts and communities to form micro grids and negotiate for cheaper power.[127]

Norway is considering setting a timeline for installation of smart meters similar to Sweden. New requirements for full scale deployment of smart meters were suggested in 2009, the final decision is postponed until the spring of 2010 pending the European decision on standardization.[128]

In **France**, EDF's distribution business ERDF announced in July 2008 Europe's largest smart metering program – a €4 billion project to install 35 million PLC connected meters. It will commence, following a 300,000 meter pilot, in 2012 and run for 5 years, with peak meter replacement volumes of 35,000 a day. From March 2010, ERDF will install 300,000 meters in the Lyon region. The testing phase will run until October 2010, with mass roll out expected between 2012 and 2016. The original article (in French) also informs that no cost

[122] *Smart Meters: Enel and Endesa Create "Meters and More",* Enel Press Release, Feb. 18, 2010, http://www.enel.com/en-GB/media/press_releases/release.aspx?iddoc=1629732.
[123] *Enel: Italy Reaping First-Mover Benefits of Smart Meters*, Feb. 3, 2010, http://www.euractiv.com/en/climate-environment/enel-italy-reaping-first-mover-benefits-smart-meters.
[124] Scott, Mark, *How Italy Beat the World to a Smarter Grid*, Businessweek, Nov. 17, 2009, http://www.businessweek.com/globalbiz/content/nov2009/gb20091116_319929.htm.
[125] Saguan, Marcelo, *Smart Metering: Summary and Conclusions*, Florence School of Regulation, Feb. 6, 2009, http://cadmus.eui.eu/dspace/bitstream/1814/11353/1/FSR_Proceedings_090206_Smart%20Metering.pdf.
[126] *Wiser Wires*, Economist, Oct. 10, 2009, pp. 71-73.
[127] Abel, John C., *Linking Smart Meters and Social Networks*, Wired Magazine May 1, 2010, http://www.wired.com/epicenter/2010/05/linking-smart-meters-and-social-networks/.
[128] *Annual Report on the Progress in Smart Metering 2009, Version 2.0,* European Smart Metering Alliance, Jan. 2010, http://www.esma-home.eu/UserFiles/file/ESMA_WP5D18_Annual_Progress_Report_2009(1).pdf.

will be passed to customers.[129] The national target for the rest would be 96% smart meters installed by 2020.[130]

In October 2008, the **UK** government announced its intention to mandate a roll out of around 50 million duel fuel smart meters to all 27 million homes by 2020. The government set high-level smart functionality requirements for smart meters and announced the initiation of a central Smart Metering Implementation Program.[131] A company will be appointed to provide a national communication channel that all meters must use. Electric meters will be supplied with a switch so that they can be remotely set as pre-payment or credit meters. There are 4 major government sponsored trials underway which are due to conclude in 2010. The UK has very high levels of customer switching, resulting in high costs for the suppliers and, when the business processes have been unable to cope, high levels of customer dissatisfaction. Smart metering is expected to improve those processes, reducing costs and increasing customer satisfaction.[132] The meter rollout is estimated to cost between £2.5 and £3.6 billion over the next 20 years.[133] In addition to other benefits, a study released by the London School of Economics has revealed that a £5 billion (US$7.4 billion) smart grid investment would create or maintain an estimated 235,000 jobs.[134]

In **Germany**, a mandatory full rollout of smart meters in under discussion. There are at least 50 pilots underway with installation plans of up to 100,000 meters per project. RWE is installing smart meters to its 100,000 customers and Rheinergie is preparing a full roll-out across Cologne until 2012. Smart meters are mandatory for new or reconstructed buildings.[135] Customers are free to choose a smart meter. Time-differentiated prices for all customers will be introduced in January 2011. To demonstrate the functioning of smart HANs for automatic load control, the project "E-DeMa" is carried out which is part of the E-Energy program. In "Smart Watts", the demonstration of automatic load control is planned.[136]

In the **Netherlands,** as part of the liberalization process, domestic metering has been made a responsibility of the customer. Customers are obliged to buy or lease a meter from a recognized metering company. Currently, low-voltage consumers may choose from simple TOU tariffs differentiated to peak hours (working days, generally 7am to 11pm) and off-peak

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[129] *35 millions de compteurs électriques communicants sur CPL en 2016 en France*, Réseaux & Télécoms, July 2, 2009, http://www.reseaux-telecoms.net/actualites/lire-35-millions-de-compteurs-electriques-communicants-sur-cpl-en-2016-en-france-20453-page-1.html.
[130] *Status Review on Regulatory Aspects of Smart Metering (Electricity and Gas) as of May 2009*, European Regulators' Group for Electricity and Gas (ERGEG), Oct. 19, 2009.
[131] *Towards A Smarter Future: Government Response to the Consultation on Electricity and Gas Smart Metering*, Department of Energy and Climate Change, Dec. 2009, http://www.decc.gov.uk/en/content/cms/consultations/smart_metering/smart_metering.aspx
[132] European Smart Metering Alliance, *supra*.
[133] Donoghue, Andrew, *Smart Meters Will Benefit UK Jobs*, EWeek Europe, May 12, 2009, http://www.eweekeurope.co.uk/news/news-it-infrastructure/smart-meters-will-benefit-uk-jobs-869.
[134] Liebenau, Jonathan et al., LSE Enterprise Ltd. & The Information Technology and Innovation Foundation, *The UK's Digital Road to Recovery*, April 2009, http://eprints.lse.ac.uk/23830/1/UK_Digital_recovery.pdf
[135] ERGEG, *supra*.
[136] *Regulatory strategies for selected Member States (Denmark, Germany, Netherlands, Spain, the UK)*, IMPROGRES, May 2010, http://www.improgres.org/fileadmin/improgres/user/docs/D8_Final.pdf.

hours, although most consumers are shielded from the fluctuations in real-time prices.[137] The incumbent utilities are performing field tests with the provision of smart metering to domestic customers. The Dutch Senate recently rejected proposed legislation including a compulsory rollout of smart meters for all 7 million households by 2014 for reasons of privacy and security. Proposed legislation and standards are now being revised for new discussion in parliament in order to allow a voluntary rollout. New decisions are expected in fall 2010.[138]

In **Spain**, the government established a rollout timetable that foresees the replacement of old meters with electronic smart meters with remote capabilities by 2018.[139] In addition, DR mechanisms should be fully operational by January 2014.[140]

In **Canada**, the Ontario Energy Board has mandated 100% smart meter deployment to begin in 2006 and be completed in 2010 with a surcharge of $3-10 per month. Legislation contains provisions for financing smart meters. As of March 2010, 3.7 million smart meters had been installed and the government of Ontario expects 3.6 million residential customers to be on TOU rates by June 2011.[141]

In 2007, the Council of **Australian Governments** committed to a mandated rollout of smart meters in states where the benefits of a rollout are expected to exceed costs. The government provided AU$100 million to fund a National Energy Efficiency Initiative to develop a Smart-Grid energy network. This demo project combining broadband with smart grid technology and smart meters in homes will enable greater energy efficiency and better integration of renewable energy sources. Victoria will become the first territory to achieve full penetration by 2013. Mandatory rollouts are being considered in other territories such as New South Wales.[142]

China's national grid company recently announced that it will deploy 500 million smart meters across the country.[143]

South Korea announced its plan to create a national Smart Grid and urged the formation of global partnerships for knowledge exchange.

In **New Zealand**, the adoption of smart metering is driven by the energy industry.[144] South Korea, New Zealand, Singapore and Japan have announced major packages to stimulate smart grid projects.

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137 IMPROGRES *supra*.
138 ERGEG *supra*.
139 Torriti, Jacopo et al., *Demand Response Experience in Europe: Policies, Programmes and Implementation*, Energy, 35 (4), 575-1583 (2010).
140 IMPROGRES *supra*.
141 "Ontario Energy Board Approves Final Dates for Mandatory TOU Generation Rates", Energy Choice Matters, August 5, 2010, p. 3.
142 *Smart Meter Penetration in Asia-Pacific Will Reach 25 Percent by 2015*, Berg Insight Press Release, June 14, 2010, http://www.berginsight.com/News.aspx?m_m=6&s_m=1.
143 Scott, Howard, *Smart Meters Surge*, EnergyBiz, July/August 2010, pp. 29-30
144 Berg Insight *supra*.

Brazil's energy regulator Aneel announced tentative plans for a nationwide rollout of 63 million smart meters by 2021.[145]

[145] *Smart Grid Development Is Not Limited to the U.S.*, KEMA Automation Insight, April 2010, http://www.kema.com/services/consulting/utility-future/smart-grid/smart-grid-not-limited-to-US.aspx.

Appendix G Comparison of Deployments in ERCOT

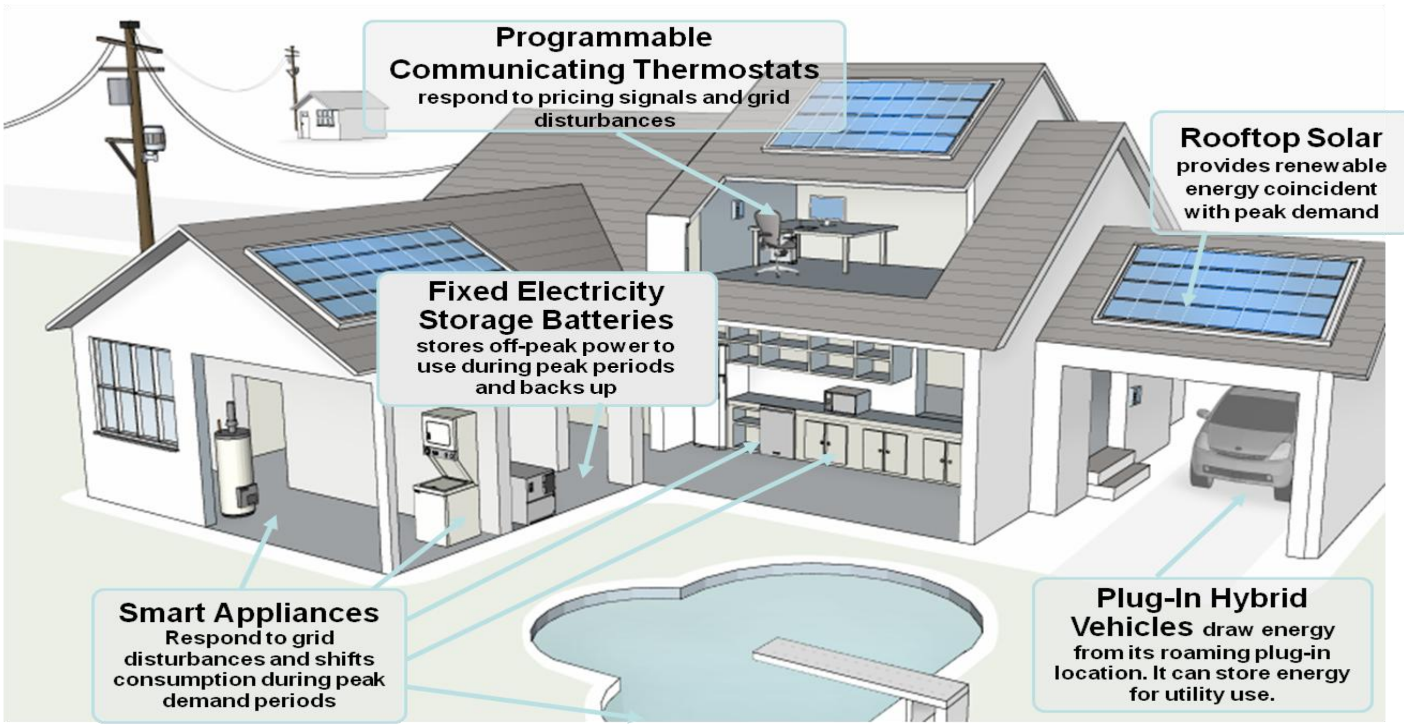
	CenterPoint	Oncor	AEP TCC**	AEP TNC***
Approximate Meters Deployed (Total)	2 Million	3 Million	809,000	193,000
Completion of Deployment	Mid-2012*	End of 2012	End of 2013	End of 2013
Total Estimated Savings	$120.6 Million	$176.0 Million	$89.2 Million	$32.6 Million
Estimated Customer Education Expense	$5.6 Million	$15.1 Million	$4.0 Million	$1.0 Million
Residential Surcharge Amount	$3.05	$2.19	$2.26	$2.35

*CenterPoint requested to accelerate its deployment in its AMS Reconciliation as part of its rate case in Docket No. 38339, Application of CenterPoint Energy Houston Electric, LLC for Authority to Change Rates.

** AEP TCC residential surcharge is $3.15 during the first two years, $2.89 during the next two years, and $2.26 for the remainder of the surcharge period.

*** AEP TNC Residential surcharge is $3.15 for the first two years, $2.27 during the next two years, and $2.35 for the remainder of the surcharge period.

Appendix H The Smart Home



Source: Wall Street Journal