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Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

March 25, 2011

**RE:** ***Consideration of the New Federal Standards of the Energy Independence and Security Act of 2007* – Case No. 2008-00408**

Dear Mr. DeRouen:

Please find enclosed and accept for filing an original and ten copies of this Joint Response report that addresses the issues raised in the Staff's Smart Meter and Smart Grid Guidance Document dated February 19, 2010 regarding the above referenced proceeding.

The process utilized to develop this report was a collaborative effort providing all parties of record the opportunity to participate in this important initiative through access to documents, revisions, and input by means of an electronic SharePoint site and several conference calls. A listing of participants that attended various meetings and conference calls during this process is included as Appendix G of this report.

The Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, along with the Commuity Action Council for Lexington-Fayette, Bourbon, Harrison and Nicholas Counties, Inc. will be filing comments separately in this proceeding.

The Joint Parties are appreciative of the overall collaboration and the opportunity to respond to the Commission regarding the deployment of Smart Meters and Smart Grids in the Commonwealth.

Should you have any questions regarding the enclosed, please contact me or any of the other Joint Parties at your convenience.

Sincerely,

Rick E Lovekamp

Rick E. Lovekamp

cc: Parties of Record

CASE PARTICIPANTS JOINT RESPONSE
TO KENTUCKY PUBLIC SERVICE COMMISSION
CASE NO. 2008-00408

# Consideration Of The New Federal Standards Of The Energy Independence and Security Act

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## In Response to Kentucky PSC's February 19, 2010 Guidance Document Letter

**March 25, 2011**

**Joint Case Participant Response to**

**Case No. 2008-00408**

**Letter Dated February 19, 2010**

CONSIDERATION OF THE NEW FEDERAL STANDARDS OF THE ENERGY INDEPENDENCE AND SECURITY ACT

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# Joint Case Participant Response to

# Case No. 2008-00408

# Letter Dated February 19, 2010

# CONSIDERATION OF THE NEW FEDERAL STANDARDS OF THE ENERGY INDEPENDENCE AND SECURITY ACT

## EXECUTIVE SUMMARY

On October 21, 2009, an Informal Conference was held at the Kentucky Public Service Commission's offices for the purpose of discussing the interest of jurisdictional electric utilities and non-utility parties in working collaboratively toward the self deployment of Smart Meter technology and time-of-use rates. Pursuant to the October 21 meeting, the Commission issued a Staff Guidance Document identifying issues which should be addressed.

Jointly on April 29, 2010, the parties responded with an Overview and Schedule for Developing Responses to the Staff's Guidance Document. This report provides a comprehensive look into Smart Meter and Smart Grid technologies for Kentucky. It addresses the issues raised in the Staff Guidance Document and will serve to educate utility customers and policymakers about the various facets of emerging smart technologies.

The American Reinvestment and Recovery Act provided approximately $4 billion for smart technologies to enhance the grid. This level of funding created a surge of emotional appeal and has driven new technological offerings from vendors. However, a note of caution is appropriate, as some vendor claims have outpaced operational deployment capabilities --- technology implementation prior to being fully tested in the operational arena. Now, the strong interest in smart grid technology, which gained massive industry attention and was accelerated by the federal stimulus funding, is in some cases not supported by current economics. Because the operational and reliability benefits may vary greatly amongst utilities, in some cases they may not be sufficient to support wide-scale deployment at this time.

Utilities have implemented infrastructure such as Supervisory Control and Data Acquisition (SCADA) which provides telemetry and remote operation of switches/breakers to control the flow of electricity across Kentucky. Partially, it is the utilities' deployment of technology such as SCADA which has produced economical and reliable energy for the Commonwealth. While some utilities have focused on transmission and distribution automation and control, others have more specifically focused on automated meter reading (AMR) and advanced metering infrastructure (AMI). Each utility has made investment decisions that are aligned with the physical infrastructure, geography of their respective customer service area, and value that the investment brings to their customers. Consequently, different utility approaches to enhancing customer benefits through implementation of technology should be seen as a positive for citizens of the Commonwealth regardless of the varying implementation mechanisms.

Smart Grid is not an "all or nothing" opportunity. It is an evolving opportunity that naturally progresses from existing infrastructure into technological capabilities where customer value can be achieved. Accordingly, investments should be incremental and sequential, following measurable value to consumers and demonstrated success in earlier phases of technology deployment. Adaptability is the key, thus avoidance of one technological solution is critical to maintaining adaptability of future technology capabilities. The implementation of Smart Grid will be a protracted evolutionary transformation and not an overnight conversion.

The development of emerging standards and the level of customer adoption of technology create new risks for companies and consumers. Smart meter technology enables consumers to take action by providing them with more information about consumption and price, while at the same time giving them the tools to make choices. Deployment of smart technology could also lead to the further convergence of supply side (distributed generation, storage) and demand side planning (load reductions, time-of-day rates). Because these strategies are unproven in the marketplace, assumptions regarding public acceptance of demand side solutions will need to be carefully tracked and refined with experience. Utilities will need to continue to address the expense and complexity of cyber security issues that continue to evolve with advancements in technology and ever-changing legal requirements. Open jurisdictional questions related to who controls the bulk electric system and the uncertainty over regulatory treatment add risk and uncertainty to jurisdictional utilities.

Despite the above challenges, the guiding principles for economic and commercial appraisal of smart systems should be the same as for any other utility investment. Specifically, all costs and benefits must be included, quantified, and allocated appropriately amongst the utility, the ratepayer, and all other contributors or beneficiaries. Uncertainties in cost and/or benefits should be addressed by appropriate risk analysis. Projects should be prioritized by net present value (NPV), investment-return ratio, or other standard financial evaluation methods which take into consideration the timing of capital costs and associated benefits.

The subsequent pages of this document delve deeper into the definition of "Smart Meter" and "Smart Grid", Smart Grid applications which can be achieved through the deployment of technology, and essential functions and components of Smart Meter and Smart Grid. Additionally, benefits to the consumer and potential cost recovery issues and mechanisms are discussed. The result is a document that provides a common basis for future discussions on the smart technology issues facing Kentucky's electric utility industry.

## 1. "SMART METER" DEFINITION

Smart Meter technology includes metering technology capable of bidirectional communication that records electricity usage on an hourly basis or more frequently, including related electric distribution system upgrades to enable the technology. Smart Meter technology must provide customers with access to, and use of, price and consumption information either directly from the meter to the customer or from the utility's information systems and (1) include information on their hourly consumption; (2) enable time-of-use rates and real-time price programs; and/or (3) effectively support the automatic control of electricity consumption by the customer, the serving utility, or a third party at the customer's request.[1]

As noted in the September 11, 2009 Commission Staff notice of informal conference, the above definition is based on a Pennsylvania statute. Revising the "must provide" portion of the second sentence to read "must have the capability to provide" might better reflect the situation in Kentucky.

Smart Meters may include additional capabilities such as (1) remote disconnect/reconnect capabilities; (2) secure two-way communications networks and information technology to support both utility's and customer's in-home device interactions at intervals of not more than 15 minutes; (3) limited local storage of consumption, pricing, and voltage data; (4) ability to upgrade meter firmware or software as technology advances without on-site technician visit; (5) ability to detect outages, interruptions, tampering, and service restorations; or (6) support net metering or two-way electric flows.

Smart Meter technology deployment and operating costs are provided in greater detail under Section 2.2.

## 2. "SMART GRID" DEFINITION

The term "Smart Grid" is generally used to describe the integration of the elements connected to the electrical grid with an information infrastructure to offer numerous benefits for both the providers and consumers of electricity. It is an intelligent electricity system that connects all supply, grid, and demand elements through an intelligent communication system.

The "Smart Grid" can be discussed in two major components:

- Smart Meters and Customer Programs communicate energy usage information to the utility and to customers in ways that allow the customer to engage in managing their energy usage while also providing more dynamic information for the utility to use in managing the electric system.
- Grid Management utilizes communication networks and intelligent controls to more reliably and efficiently operate the electric system while providing more visibility and security for system operators.

The Energy Independence and Security Act (EISA) of 2007 table below identifies ten characteristics of a Smart Grid and outlines how these major components work together to embody the characteristics of the "Smart Grid".

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[1] Case No. 2008-00408 Commission Staff notice of informal conference, September 11, 2009.

| Characteristics of a Smart Grid [2] | Smart Metering | Grid Management |
|---|---|---|
| 1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid. | X | X |
| 2. Dynamic optimization of grid operations and resources, with full cyber-security. | | X |
| 3. Deployment and integration of distributed resources and generation, including renewable resources. | X | X |
| 4. Development and incorporation of demand response, demand-side resources, and energy-efficiency resources. | X | X |
| 5. Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering; communications concerning grid operations and status; and distribution automation. | X | X |
| 6. Integration of "smart" appliances and consumer devices. | X | |
| 7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning. | | X |
| 8. Provision to consumers of timely information and control options. | X | |
| 9. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid. | X | X |
| 10. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services. | X | X |

While the term "Smart Grid" typically relates to the electricity grid, it is important to note that its definition emulates in the natural gas utility market as well. The intelligent gas grid can employ

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[2] Section 1301 of EISA 2007, in setting forth the policy of the United States, identifies ten characteristics of a smart grid stating, "It is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve each of the following, which together characterize a smart grid:"

many of the same functionalities as the smart electricity grid, through integration of advanced network communications and smart gas meters[3].

### 2.1 Effective Smart Grid Applications With and Without Time-of-Use Rates

The efficacy of Smart Grid applications does not depend on the implementation of time-based or incentive-based rate structures. For example, smarter technologies for transmission and distribution (T&D) automation and controls could be implemented and achieve benefits without any changes to rate structures. However, the implementation of these rate structures would likely impact both the design of Smart Grid solutions and the expected costs and benefits. A list of specific pricing rate structures that may be deployed in Smart Grid applications is detailed in Appendix B of this report.

Increased communications requirements

The communications infrastructure requirements will be dependent on the amount, frequency and latency of information that is being transmitted between the customer and the utility, as well as communication within the utility transmission and distribution systems and substations. Without having to support large-scale time-of-use (TOU) / dynamic rate offerings, bandwidth requirements would be significantly reduced.

More frequent meter reads (*e.g.*, on an hourly basis or less)

Smart Meter functionality could allow the utility to collect usage data from customers more frequently and support time-differentiated interval measurement. These new measurement capabilities could allow for new rate structures and could support increased customer awareness of their energy usage. New rate structures may dictate the frequency at which Smart Meter data will be recorded and stored. While these advancements could provide both system and customer benefits, it will be important to determine the optimal interval and level of data collection, because the cost of data management and storage, including resource requirements to properly maintain the data captured, will likely scale up as the frequency of meter readings posted to centralized data repository increases.

Providing customers with increased visibility of energy prices and near real-time consumption information

In order to assure universal access to data across all customer segments, multiple communications channels would be needed to convey granular energy use information to customers. Potential channels include web portals, in-home displays, physical mailings,

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[3] Natural Gas in a Smart Energy Future – A strategic resource for electricity and a smart resource for homes and businesses, January 2011, gti, is included in Appendix C

telephone communications, and electronic mail. Granular energy use information would need to be available in a timely manner in order for customers to respond to price signals and/or utility requests to curtail consumption. Furthermore, endpoints, in-home devices, and automated communications may be required to align the price signals and/or load-curtailing requests to customer decision making.

Support for the automatic control of the customer's electric consumption

With time-of-use rates in place, customers may demand utility assistance in terms of optimizing their energy consumption to minimize energy costs. This would further emphasize the need to measure and communicate demand-side management program impacts and benefits with respect to impacts on the cost to serve and the customer bill.

Overall, these rate structures would potentially allow customers to extract more value out of demand-side management programs. It would also increase the amount of supporting infrastructure (data management and analysis requirements) that must be provided by the utility as well as organizational improvements (*e.g.*, to customer relationship management processes) to serve customers in new ways. Because advanced metering infrastructure is thought to enhance the management of large-scale demand-side management (DSM) programs, the energy and capacity benefits associated with DSM programs like TOU rates have been frequently used by other utilities to rationalize investments in Smart Meters. However, TOU programs typically allow for voluntary customer participation which can make quantification of economic benefits in planning models unpredictable. In addition, risk of customer dissatisfaction associated with TOU rates (due to complexity of billing related to usage) needs to be taken into serious consideration. Technologies which could support alternative rate structures capable of achieving benefits through DSM programs, and be transparent to customers, would be ideal, but continue to evolve. Utility's actions to minimize coincident peak in small geographic areas by automatic control of consumer-owned appliances through Smart Meter and Smart Grid technologies present important societal and influential policy issues which may require further consideration.

## 2.2 Individual incremental costs for deploying and operating Smart Meter technology capabilities

The following capabilities are among those which may be supported by Smart Meter technology:

- Ability to remotely disconnect and reconnect
- Ability to provide 15-minute or shorter interval data
- On-board meter storage of meter data
- Ability to upgrade these minimum Smart Meter capabilities as technology advances and becomes economically feasible

- Ability to monitor voltage at each meter and report data in a manner that allows the utility to react to the information
- Ability to remotely reprogram the meter
- Ability to detect outages and restorations
- Ability to support net metering of customer generators

The individual incremental costs for deploying and operating capabilities noted above may only be derived accurately through detailed cost analysis which would include utility-specific variables and parameters (*i.e.*, geographical nature of utility's service territory, network performance for the smart grid applications to be supported, the number of network devices, *etc.*).

Costs for smart meters typically vary based on vendor, presence of a service connect/disconnect switch, presence and choice of in-premises communications technology, memory storage requirements, advanced metering or firmware upgrade capabilities, meter form factor, etc. The cost of the smart meters is only one component of a complete Smart Meter system. Utilities typically compare the total cost of their Smart Meter system installation averaged across the total number of meters installed. This allows the utility to include other major cost elements of the Smart Meter system such as the Smart Meter network, enterprise systems required to operate the Smart Meter system, development costs, and installation costs. Average installed system costs for large utilities typically start at $250 per meter when averaged across very large numbers of meters and include basic capabilities such as (1) two-way communications networks and information technology to support both utility's and customer's in-home device interactions at intervals of not more than 15 minutes; (2) limited on-board meter storage of consumption, pricing, and voltage data; and (3) ability to detect momentary outages, tampering, and service restorations. Additional capabilities include (1) ability to remotely disconnect and reconnect; (2) ability to upgrade meter firmware or software as technology advances without on-site technician visit; and (3) ability to support net metering or two-way electric flows. These capabilities could potentially increase the cost of an installed system to $350 per meter.[4]

The high-level costs for grid management efforts (*i.e.*, automatic circuit reconfiguration, asset sizing optimization and condition monitoring, improved fault location, Volt/VAR management, voltage optimization, system protection of distributed resources, communication bandwidth and availability of fiber, *etc.*) are largely dependent on utility specific geography, customer density, transmission and distribution configurations. If included, general cost projections may be misleading since those values may vary extensively by each utility.

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[4] Smart Meter costs, while varying somewhat based on vendor selection and hardware configuration, have decreased significantly over the past couple of years. More recent Smart Meter proposals and filings suggest that all of the capabilities mentioned are typically included in an installed system cost of $250 per meter.

## 3. THE ESSENTIAL FUNCTIONS OF SMART METER AND SMART GRID SYSTEMS

### Smart Meters

As stated above, a specific Smart Meter definition was provided as part of Case No. 2008-00408 on September 11, 2009 in a Commission Staff notice of an informal conference. The detailed definition was as follows:

"Smart Meter technology is defined as including metering technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. Smart Meter technology must provide customers with direct access to and use of price and consumption information, to include (1) direct information on their hourly consumption; (2) to enable time-of-use rates and real-time price programs; and (3) to effectively support the automatic control of electricity consumption by the customer, the serving utility, or a third-party, at the customer's request."[5]

The intent here is to augment this initial definition by defining basic and advanced functions for Smart Meters and Smart Grid as well as discussing the technology and infrastructure requirements for these functions.

Basic Smart Meter functionality relies on solid-state meters, two-way communications infrastructure, and a meter data management solution that, at a minimum, is integrated with the utility's billing software. This basic configuration would support the core functions of Smart Meters:

1. Remote meter reading – automation that would reduce meter reading activities that are currently performed manually.
2. Remote meter configuration – meter reprogramming, resets, verifications, *etc.*, would not require manual field work as they would be able to be performed remotely.

Based on the required function set, a utility can move beyond the basic configuration by adding field equipment (*e.g.*, remote connect/disconnect relays, home area network-enabled communications chips), further information technology implementations, and integrations (*e.g.*, integration with other systems that could include outage management, demand response management, geographic information management, and work management) as well as supporting organizational changes to provide any of the following functions:

1. Remote connect/disconnect/reconnect -- In response to both customer requests and non-payment.

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[5] As noted previously, to better reflect the situation in Kentucky, the "must provide" portion of the second sentence could be revised to read "must have the capability to provide."

2. Remote consumer price signals – Providing notifications about on- and off-peak pricing to consumers through the advanced meter in order to support demand-side management programs.
3. Remote identification of outage events – Currently, a utility can detect wide-scale outage events through use of Supervisory Control and Data Acquisition (SCADA) systems employed in the transmission and distribution sectors. However, the capabilities for identifying the occurrence or extent of an outage event, at customer premise level are limited. One potential function of Smart Meter technology is the ability for the utility to ping Smart Meters to verify active service, provided reliable communications are in place. This capability could be leveraged to provide for the proactive identification of individual outage events – including location, extent, and restoration status. Furthermore, it could allow the utility to respond to outages and begin power restoration efforts before the customer even knows an outage has occurred, thus reducing outage duration by allowing the utility to work more efficiently. It is important to note that any proposal must carefully integrate Smart Meters into existing outage management procedures as the observance of meter failures could falsely indicate outage events and result in added outage response costs.
4. Provision of granular energy use information to customers – Type of information, and frequency at which information is provided, would depend on the alternative rate programs being offered by the utility. In general, this type of data would enable the customer to participate in demand-side management programs as well as other in-home offerings (*e.g.*, home area networks).

## Smart Grid

The term Smart Grid in this context encompasses the increased monitoring, remote control, and automation of the transmission and distribution grids. Overall, the essential functions of a Smart Grid are:

1. Remote monitoring of sensors in the field – Installing a series of sensors throughout the transmission and distribution (T&D) grid to monitor pre-defined network parameters. Then, provide the communications and data analytic tools to perform extensive measurements and advanced diagnostics to support grid state determination and other diagnostic functions.
2. Remote control of field devices – Ability to remotely control grid components (*e.g.*, switches, reactive power equipment, protective equipment, *etc.*) throughout the T&D grid.
3. Increased fault intelligence – Utilize information from sensors and databases to remotely monitor protective devices, better detect the location and type of faults, and suggest actions to isolate them and reduce their impact.

4. <u>Improved outage detection, management, and restoration</u> – Once an outage has occurred, utilizing sensors to map outage extent, to perform root cause determination, to optimize switching and crew dispatching, and track and verify restoration progress.
5. <u>Customer notification of outage events and restoration status</u> – In conjunction with enhanced outage identification capabilities, the utility could also proactively provide notifications to customers. This would reduce the need for customers to call their utility and would provide a channel for utilities to manage customer expectations with respect to outage response and restoration activities.
6. <u>Enhanced power flow control</u> – Utilize sensing and controls to switch power to different parts of the system to reduce line losses.[6] This function would also support remote and adaptive flow control and load balancing.
7. <u>Power quality (PQ) optimizations</u> – Ability to detect PQ issues (*e.g.*, voltage fluctuations, harmonics) and suggest solutions. This function would also include equipment and analytics used to identify and correct phase alignment issues in order to reduce losses and ensure system stability.
8. <u>Condition-based maintenance</u> – Use of the deployed sensor network to predict failure of system components and implement comprehensive preventative maintenance programs that may increase the average life of grid assets. This function would also include the leveraging of more robust grid state data to increase system planning efficiency.
9. <u>Integration of distributed resources, renewable supply resources and storage resources</u>.

## 4. THE ESSENTIAL COMPONENTS OF SMART METER AND SMART GRID

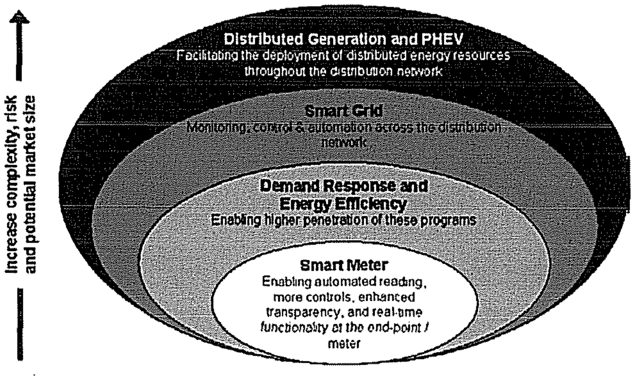

FIGURE 1

Four areas contemplated for a fully developed and functional Smart Grid are (a) Advanced Metering Infrastructure (AMI), (b) Demand Response (DR)/ Energy Efficiency (EE), and (c) Distribution Automation (DA), Transmission Automation (TA), and (d) Distributed Generation (DG), and Plug-in Hybrid Electric Vehicles (PHEVs) as shown in Figure 1. At a minimum, each of these areas is interdependent but may be independently implemented. As areas are implemented and integrated, the system provides for increasing enhancements and efficiencies for subsequent expansion.

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[6] To successfully accomplish this task the utility may have to consider dynamically moving load between circuits and even substations. Circulating currents caused by tying circuits from different substations will have to be monitored in order to prevent individual circuit lock outs.

Providing customers with technologies and detailed usage information, coupled with education, will empower them to make decisions about their personal energy consumption. Deployment of Smart Meter technology will pave the way for future integration of DR savings and a much different customer interaction than has been historically possible with one-way communication to DR devices.

As observed by many industry experts, there is no single technology which can meet all the Smart Grid criteria. An integrated solution involving the strengths from Geographic Information System (GIS), AMI, Outage Management System (OMS), Distribution Management System (DMS), DA, and SCADA would be needed to deliver overall Smart Grid functionality. These components are mapped against the smart meter and smart grid functionality in the table below from the U.S. Department of Energy (DOE). [13]

| **DOE Smart Grid Matrix** | GIS[7] | AMI[8] | OMS[9] | DMS[10] | DA[11] | SCADA[12] |
|---|---|---|---|---|---|---|
| Enabling informed participation by consumers in retail and wholesale electricity markets. | X | X | X | | | |
| Accommodating all types of central and distributed electric generation and storage options. | X | | | X | | X |
| Enabling new products, service, and markets. | X | X | X | X | X | X |
| Providing for power quality for a range of needs. | X | | | X | X | X |
| Optimizing asset utilization and operating efficiency of the electric power system. | X | | X | X | X | X |
| Anticipating and responding to system disturbances. | X | | | X | X | X |
| Operating resiliently to attacks and natural disasters. | X | X | X | X | X | X |

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[7] GIS defines consumer connectivity to the grid and overall network topology.

[8] AMI provides the consumption information to various points throughout the grid for analysis and display.

[9] OMS integrates the GIS, AMI, and DMS to provide restoration crew dispatch, assignment, and management.

[10] DMS provides distribution network analysis, load estimation, load forecasting, and network simulation.

[11] DA provides real-time grid monitoring and automated controls based upon a set of conditions, models, and algorithms to maximize overall system reliability.

[12] SCADA provides real-time grid monitoring and control.

[13] Public Utilities Fortnightly's SPARK, Letter #70, October 2009; DOE Office of Electricity Delivery and Energy Reliability, http://www.oe.energy.gov/DocumentsandMedia/TechnologyProviders.pdf

### 5. BENEFITS FROM SMART METER FUNCTIONALITY

When fully implemented, a Smart Meter solution, depending on its intent and scope, could have a wide ranging impact on both utility operations and on the customer experience. These benefits are outlined below and in Figure 2. It is important to note that the impacts of Smart Meters listed here are meant to highlight those that have been observed or claimed across the industry. It would not be possible to claim measurable improvements to operations or overall cost effectiveness without a more advanced Smart Meter solution design or a more detailed assessment of the service territory.

At a high level, Smart Meter benefits can be organized into the following categories:

1) Optimize O&M costs

   While initial asset replacement and installation costs may be higher, minimization in meter reading and meter-related field operations (*i.e.*, vehicle management, personnel injuries) costs could optimize ongoing O&M costs that are incurred by the utility and charged directly to the customer. Typical jobs that could be reduced with Smart Meters, dependent upon deployed functionality as described in Section 1, that are performed manually today include:

   - Monthly meter reads,
   - Meter re-reads (per customer requests),
   - Meter inspections,
   - Meter reprogramming,
   - Meter repairs,
   - Meter testing,
   - Service connects for new customers,
   - Service disconnects for customer move outs and non-payment, and
   - Service reconnects.

2) Enable large scale DSM

   Smart Meters are critical to support large scale comprehensive demand-side management and time differentiated rate programs (*e.g.*, time-of-use rates, critical peak pricing (CPP), peak time rebates (PTR), real-time pricing (RTP), energy efficiency programs, *etc.*). By being able to monitor customer energy use remotely, utilities may be able to manage these programs in a more cost effective manner while providing customers with the tools and information necessary to deliver measureable energy and cost savings. Providing customers with consumption and price data is important, however, with the current level of technology available, customers must act on the information to benefit themselves and the grid. Overall, these benefits could include:

   - Capacity benefits from reduced peak loads;

- Energy benefits due to increased energy efficiency and/or conservation; and
- Reduced DSM program management costs (w/Smart Meter vs. w/o Smart Meter).

3) Improve cash flow management

Cash flow management is very important for a utility and Smart Meters could drive significant improvements. Two potential drivers for this improvement could include:

- Remote meter reading could reduce or eliminate the need for bill estimation, thereby reducing customer bill complaints and improving timeliness of bill payments, and
- Automated meter reading could reduce duration of bill preparation time (typically done over a period of a few days for each billing cycle), thereby increasing collections time for accounts receivable.

4) Reduce energy theft and consumption on inactive meters

Smart Meter systems could also be leveraged to improve revenue assurance processes dealing with detection of energy theft and consumption on inactive meters. This could be accomplished by leveraging advanced data analytical tools and Smart Meter consumption data to detect instances of meter tampering or unbilled consumption that are otherwise difficult or expensive to detect. This would help ensure that other customers are not unfairly burdened by these unbilled energy costs since currently these costs are written off and charged to all customers as they are incurred.

5) Improve bad debt management

Bad debt, when written off, is a cost that burdens all customers. Smart Meter provides functionality that could be leveraged to improve management of uncollectible accounts. Today, utilities perform analysis of past due accounts and will disconnect certain accounts for non-payment once certain past due thresholds are reached. Even if existing bad debt management processes are retained, the utility could leverage remote connect/ disconnect functionality to perform these disconnects in a more timely manner. Furthermore, with more granular energy use information, the utility could also make changes to overall processes used to manage past due accounts. This may require organization changes with respect to these status quo processes as well as sensitivity toward low-income customers.

6) Provide additional reliability data

Improvements to reliability statistics (*e.g.*, System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI)) can be monitored and measured. However, since these metrics vary over time, it is difficult to attribute changes to any singular initiative. Furthermore, estimating the monetary impact of improved reliability on the customer bill is also a difficult task. Due to the complex nature of operational and capital budgeting processes, it would be difficult to precisely attribute changes over time to Smart Meters.

7) Increase customer satisfaction

Estimating the financial impact on the utility value chain from improvements to customer service is difficult. Key Smart Meter functions that could improve customer satisfaction include:

- Automating many meter-related activities in order to reduce the number of customer complaints,
- Reducing the number of times utility personnel need to intrude on the customer premise,
- Increasing the amount of information available to call center personnel when they are working with customers to resolve issues,
- Proactively notifying customers of events like faults and outages,
- Improving system operations and increasing distribution automation capabilities to improve traditional reliability statistics (*e.g.*, SAIDI and CAIDI),
- Allowing for quicker customer service when performing customer-requested disconnects and reconnects (with remote disconnect / reconnect capability), and
- Remote disconnect / reconnect capability does not require customer to be on-site for inside meter installations.

8) Improve distribution system planning and design

Detailed energy usage information can assist engineers with analysis of load flows, planning of system capacity, and identifying reliability issues. While this could result in improvements to system design and capital utilization, the financial impact would be hard to quantify as it would be measured relative to capital expenditure forecasts and in a capital constrained environment, avoided capital expenditures would likely be reallocated to other capital projects.

9) Improve integration of customer generation assets

Smart Meters could improve the utility's ability to manage large net metering programs which would be important for the grid connection of customer generation assets ranging from photovoltaics to PHEVs.

## 6. BENEFITS FROM SMART GRID FUNCTIONALITY

The previously defined Smart Grid functions would provide information and capabilities to optimize reliability, efficiency, environmental impacts, and safety. Overall, the benefits of Smart Grid can be organized into the categories listed below. It is important to note that the Smart Grid impacts listed here are meant to highlight those that have been observed or claimed across the industry. It would not be possible to claim measurable improvements to operations, or overall cost effectiveness, without a more advanced Smart Grid solution design or a more detailed assessment of existing infrastructure and operational needs across the T&D footprint.

1) Optimize operating costs

   Increasing the level of automation throughout the transmission and distribution networks can reduce the reliance on manual operations. Some potential benefits could include the optimization of:

   - Maintenance costs for substations and feeders,
   - Inspection costs for substations and feeders,
   - Operating costs for system phase balancing,
   - Operating costs for system voltage correction, and
   - Manual switching costs.

2) Optimize distribution capital

   Smart Grid technologies will dramatically increase the granularity and frequency of data collection throughout the transmission and distribution networks. This data would be available to utility personnel (including system planners), thereby improving the overall understanding of grid operations and power flows. Once the full investments in smarter grid technologies are deployed, these system data collection capabilities could impact transmission and distribution capital costs. More specifically:

   - Improved capital efficiency and network design due to increased data and visibility of power flows and system performance, and
   - Asset life extension due to optimized system operations, better control of overload conditions, and expanded preventative maintenance capabilities.

3) Minimize line losses

   Smart Grid involves not only sensors but also remote or automatic control capabilities for specific field equipment (*e.g.*, switches, load tap changers, capacitors). Being able to coordinate control of these devices in real-time could provide new tools to system operators that are currently unavailable due to heavy reliance on manual operations. More specifically:

   - Additional system optimization and power flow control could lead to reduced line losses which will reduce the total MWh generated and total fuel consumption, and

- Minimized line losses also have corresponding peak load reductions that could impact planned investments in generation and transmission plants.

4) Provide additional reliability data
Increased visibility and the ability to alter grid state remotely, beyond current capabilities, are functions that could prove valuable and drive clear benefits when trying to manage fault conditions to prevent or shorten outage events or when field crews are responding to outage events. For example:
   - Additional real-time grid state information could be leveraged by field crews to improve outage restoration efforts, thereby resulting in system-wide reductions in the duration of outage events (CAIDI);
   - Additional real-time grid state information and remote grid control capabilities could be used to either avoid outage events or reduce the extent (*i.e.*, number of customers impacted) of an outage event, thereby resulting in a system-wide reduction in the frequency of outage events (System Average Interruption Frequency Index (SAIFI)); and
   - Power monitoring capabilities could reduce power quality events for customers with critical loads, thereby improving overall reliability.

5) Increase customer satisfaction
Estimating the financial impact on the utility value chain from improvements to customer service is difficult. In addition to Smart Meter impacts on customer service, Smart Grid functions that could improve customer satisfaction include:
   - Enhancing system operations and increasing distribution automation capabilities to improve traditional reliability statistics (*e.g.*, SAIFI and CAIDI), and
   - Improving power quality in order to enhance the quality of electric service to critical customers (*e.g.*, large industrial and commercial accounts with sensitive / specialized electricity requirements).

6) Reduce the impact of service interruptions
Improved situational awareness, utility outage management, and restoration capabilities could drive improvements to reliability statistics and may result in fewer total outage minutes for customers. This benefit is a reflection of the fact that service interruptions have a financial impact on customers. Specifically, this opportunity cost can be significant for large commercial and industrial customers.

7) Reduce environmental impact
The Smart Grid can enable increased energy sustainability and can help accommodate the adoption of alternative energy technologies like customer photovoltaics and energy

storage devices. Deployment of these alternative energy resources could lead to reductions in the carbon intensity from the energy supply options. More specifically, Smart Grid technologies may lead to reduced levels of carbon emissions by:

- Reducing total consumption levels,
- Enabling the deployment of alternative energy resources and distributed generation,
- Minimizing T&D system losses,
- Minimizing total fleet miles traveled due to increased automation that would improve the efficiency and reduce the workload of field crews, and
- Reducing levels of $SO_3$, $SO_2$, NOx and other emissions that correspond to less MWh consumed / generated from fossil fuel resources.

### FIGURE 2: SMART METER FUNCTIONS AND BENEFITS

| Smart Meter Function | Benefit | Description | Quantifiable? |
|---|---|---|---|
| Remote meter reading | Optimize O&M costs | Minimize manual meter reading costs (both monthly and customer requested re-reads) | Yes |
| | Improve cash flow management | Remote meter reading will minimize the need for bill estimation | Yes |
| | Improve distribution system planning and design | More granular customer energy use data can be used to support system upgrades, planning, and design | Yes, but difficult |
| | Increase customer satisfaction | Potential to reduce human errors resulting in customer complaints | No |
| Remote consumer price signals | Enable large scale demand side management | Price signals - either through the meter or via a customer portal - will allow the customer to better take advantage of variable / dynamic rate structures | No |
| | Increase customer satisfaction | Proactive notifications inform customers and reduce potential frustration with new rate structures | No |
| Remote meter configuration | Optimize O&M costs | Minimize meter-related field operations costs (i.e. inspections, reprogramming) | Yes |
| Remote connect / disconnect / reconnect | Optimize O&M costs | Minimize meter-related field operations costs (i.e. meter connects/disconnects/reconnects in response to both customer requests and non-payment) | Yes |
| | Improve bad debt management | Remote disconnect and more granular energy use info could allow the utility to lower bad debt and could reduce the $ amount that is written off and charged to all customers | Yes |
| Remote ID of outage location, extent, and restoration status | Additional reliability data | Being able to ping meters to check if power is on or off could help the utility ID outages before they are reported by customers and could also help confirm service restoration. | No |
| Customer notification of outage events and restoration status | Increase customer satisfaction | Automated / electronic notifications inform customers when their service will be restored and could help manage their expectations and allay their dissatisfaction due to outage | No |
| Provision of granular energy use information to customers | Enable large scale DSM | Energy use information provided to the customer may increase customer awareness of energy consumption and improve efficacy of DSM programs | No |

### FIGURE 3: SMART GRID FUNCTIONS AND BENEFITS

| Smart Grid Function | Benefit | Description | Quantifiable? |
|---|---|---|---|
| Remote monitoring of sensors | Optimize operating costs | Minimize field work for inspecting substation and feeder equipment | Yes |
| | Optimize distribution capital costs | Improved capital efficiency and network design due to increased data and visibility of power flows and system performance (after initial investments) | Yes, but difficult |
| Remote control of field devices | Optimize operating costs | Minimize field work - e.g. manual switching and other equipment operations | Yes |
| | Optimize distribution capital costs | Visibility and remote control capabilities could help optimize system operation and provide better control of overload conditions | Yes, but difficult |
| Increased fault intelligence and improved outage management | Optimize operating costs | Access to real-time data and remote / auto controls capabilities could minimize or shorten field work done in response to faults and outages | Yes |
| | Additional reliability data | Pre-emptive fault detection and faster outage response could help prevent outage events from occurring (reduce SAIFI) and could reduce the duration of those outage events that do occur (reduce CAIDI) | No |
| | Minimized cost of outages | Customers - especially the commercial and industrial segments - incur costs during outage events that would be reduced if total number of annual outage minutes are reduced | No |
| Enhanced power flow control | Minimize line losses | System optimization and power flow control could lead to reduced line losses which could reduce the total MWh generated and, with corresponding reductions in peak load, could lead to the avoidance or deferral of future capital investments in generation and transmission plants | No |
| | Minimize environmental impact | Reduced consumption of fossil fuels would lead to reductions in corresponding emissions (e.g. SO2, SO3, NOx, CO2) | No |
| Power quality optimization | Optimize operating costs | Minimize or eliminate field work for system phase balancing and/or voltage correction | Yes |
| | Additional reliability data | Monitoring and remote power flow control capabilities would reduce power quality events for customers with critical loads | No |
| Condition-based maintenance | Additional reliability data | Could help the utility manage fault conditions before they occur and trigger outage events | No |
| | Optimize distribution capital costs | Could help the utility manage their assets more proactively to avoid costly equipment failures and replacements | Yes, but difficult |

## 7. THE QUANTIFICATION OF SMART GRID AND SMART METER BENEFITS

There are many challenges associated with performing cost-benefit analysis of Smart Grid investments. Typically, the investment required may involve third parties in addition to the utility. For example, programs requiring an on-premises device may rely on having the customer or third party[14] make this initial investment. Also, the benefits realized by a Smart Grid investment may extend well beyond the boundaries of the investing utility and its customers to third parties or society as a whole. Finally, the benefits realized by customers who participate in Smart Meter programs and applications will be different from those who choose not to actively participate. Cost-benefit analysis is different from most traditional analyses in which the potential investor incurs the full cost and the investment decision is based on the cash flows that are expected to revert directly back to the investor. This lack of consistency between the investor and the beneficiary adds a level of complexity to Smart Grid cost-benefit analysis.

In addition, the investment costs of the various Smart Grid and Smart Meter alternatives can be significant and must be taken into consideration when performing any cost-benefit analysis. Because much of the technology associated with Smart Grid solutions is rapidly developing and hence seeing great variability in pricing, quantifying these investment costs can be difficult. However, the resulting consumer bill impact from these investment costs will be a major factor as customers determine whether they wish to avail themselves of the promised benefits of Smart Grid and Smart Meter technologies.

From a Smart Meter technology perspective, quantifiable benefits may include (1) decreased cost for service connection and disconnection, (2) decreased roll time of vehicle fleet during outages, and (3) decreased interruptions to commercial and industrial customers sensitive to minimal voltage fluctuations detected through voltage monitoring at each meter (*i.e.*, lost payroll, lost production). However, the value of decreased outage times for customers, while obvious, is somewhat subjective and hence not as easily quantified. Figure 3: Smart Grid Functions and Benefits shown in Section 6 captures specific functions that may or may not be quantifiable.

Since Smart Grid is so technologically driven, utilities implementing any Smart Grid strategy face the dilemma usually associated with adopting new technology. Currently, various Smart Grid vendors promote a variety of functions and/or capabilities for their individual product offerings. However, all of these features may not be able to function in concert with one another

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[14] Third party service providers (*i.e.*, Google, Microsoft, Cisco, Apple, Honeywell, Johnson Controls, Verizon, AT&T, etc.) offer resources designed to engage customers by making data available to them in ways that become integrated into the daily lives of individual and business consumers.

at a given point in time, or may still be in early product development stages. Any utility that is planning a Smart Grid deployment must robustly address this issue within its technological architecture and make sure that is reflected in the business case for the deployment.

Across the industry, cost effectiveness tests are used in order to determine whether or not a project makes economic sense for customers. Specific tests were outlined by the California Public Utility Commission in its 2001 Standard Practice Manual and have been used as a standard starting point by many utilities outside of California. [15] There are three tests or groups of tests that are important to consider when evaluating Smart Meter, Demand Response, and Smart Grid proposals. These tests are:

**Participant and Non-Participant Tests** – These tests are particularly relevant when evaluating the deployment of time- or incentive-based rate programs that are not conditions of service. No matter the cost recovery mechanism, rate impacts need to be assessed for those customers who are participating in a particular program and for those who are not. This is imperative in order to ensure equity so that customers are not charged unfairly for programs that do not impact them.

**Total Resource Cost Test (TRC)** – This test compares the net present value (NPV) of the benefit stream to the NPV of expected program costs. It has become a very popular test used to evaluate the cost effectiveness of Smart Meters and Smart Grid proposals. Typically, the benefits used for this test are limited to those that the utility can easily control, implement, and measure.

**Societal Test** – This test is built upon the TRC test and adds some perspective on the societal impacts of Smart Meters and Smart Grid. Some societal impacts that can be monetized include emissions (assuming that carbon pricing becomes a reality) and improvements to reliability that could drive indirect benefits such as economic development and avoided customer outage costs.
Two specific filings demonstrate variations in how utilities have employed cost effectiveness tests. In its 2009 Smart Grid filing (Case No. 9208), Baltimore Gas & Electric (BG&E) relied heavily on energy and capacity benefits within the PJM marketplace in order to justify the expected capital costs for a universal rollout of advanced metering infrastructure. Other than that, BG&E relies heavily on traditional AMI benefits that are most directly related to the operation of the meter. These benefits include "reduced meter reading costs, better detection of leakage (*e.g.*, theft, consumption on inactive meters, and slow meters), and avoided capital costs

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[15] "California Standard Practice Manual – Economic Analysis Of Demand-Side Programs And Projects." California Public Utility Commission, October 2001.

associated with equipment that otherwise would have been installed (*e.g.*, the need for non-AMI meters and more robust transmission investments).[16]

There are many other concepts involved in the quantification of benefits. Some of these concepts include:

**Benefits for Stakeholders Depend on Asset Type** – From a utility perspective, it is also important to note that cost-benefit analysis (as well as motivations and incentives) will vary for each specific entity (*e.g.*, integrated utilities, distribution companies, transmission operators, municipalities, cooperatives, renewable energy developers, *etc.*). This variation will be a result of many factors including the type and condition of an entity's assets. Entities with large peaking generation fleets are likely to suffer disproportionate negative impacts in the event of significant load destruction as peak loads could be reduced to the point where unit utilization rates decline and dispatch becomes uneconomical. On the other hand, entities with large base load and mid-merit fleets could benefit from a utilization standpoint as load is shifted off peak. Furthermore, depending on how federal carbon legislation evolves, companies that own or operate large gas, nuclear, or renewable generation fleets could benefit from both the allocation of carbon emissions credits and the reordering of the dispatch stack (if carbon pricing is significant). No matter the impact, the fiscal health of these entities must be considered and protected as many of these generation assets will likely still be depended on to provide high quality reliable electric service even with the implementation of robust Smart Meters and Smart Grid solutions.

**Cost and Benefit Estimates Are Moving Targets** – Also, for all cost-benefit analysis, the costs and benefits that are quantified are done as a snapshot in time. Investment costs, customer behavior (*e.g.*, consumption levels and timeliness of bill payment), and utility-incurred operational costs are always in flux and many of these factors directly impact benefits or cost reductions that would likely be attributed to Smart Meter and Smart Grid projects.

**Benefits Depend on Rate Case Timing** – In order to get a realistic view of the cost and benefit impacts for the various stakeholders, it is also necessary to understand the likely time schedule of future rate cases. If there is a time lag between project investments, operational cost reductions, revenue realization, performance improvements, and rate cases, a situation of over- or under-recovery could result for the utility. While this occurrence may not be avoidable, it should at the very least be identified and the impact on cost effectiveness should be quantified. Also,

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[16] "Application of Baltimore Gas and Electric Company for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge Mechanism for the Recovery of Costs." BG&E, Case No. 9208, July 13, 2009.

depending on the cost recovery method, this timing may also impact the likely timing of capital cost recovery via a potential rider mechanism.

## 8. AVOIDING SMART GRID AND SMART METER OBSOLESCENCE

Overall, technology obsolescence is a risk that cannot be avoided when looking at capital investments in Smart Grid technologies that are not standardized or mature. Instead, utilities are looking at mitigating this risk as much as possible, and can do so by evaluating technical attributes as well as standards that are under development and vendors that are currently offering products in the marketplace.

With respect to evaluating technical attributes of potential Smart Grid infrastructure investments, the National Association of Regulatory Utility Commissioners (NARUC) has outlined three attributes that should be considered when assessing technology obsolescence. These attributes are upgradeability, latency, and bandwidth.

- Upgradeability: When looking at specific vendors and technologies, it is important to evaluate the ability of the embedded software in a device (or firmware) to be upgraded. In light of new capabilities, software bugs, or security threats, the ability to remotely upgrade the firmware should be provided and this will help ensure that technology investments stay up to date and operate efficiently for as all long as possible.
- Latency: This is a technical attribute of the communications network and all field equipment (*e.g.*, sensors, advanced components that are communications-enabled) will have latency requirements to ensure they function properly and are able to be remotely monitored and controlled. Latency refers to "the speed with which network data is transmitted or processed" (low latency = quick connection; high latency = less frequent and more delayed communications). Based on the Smart Meter or Smart Grid solution being proposed, the latency tolerance of the field equipment being attached to the network must be understood. For example, data transfers from Smart Meters to the utility are likely not to be used to support real-time operations and, therefore, a higher latency network would be acceptable in order to reduce overall cost. On the other hand, Smart Grid applications are likely less latency tolerant as grid state information that would be transmitted from the field into the control room would be used in real-time to support operations. Overall, the trade-off is between lower latency and cost and in order to assess this properly, a strong understanding of current and future functional requirements is critical.
- Bandwidth: This is a second technical attribute of the communications network and it represents "the size of the data packages that can be sent via a network connection." Depending on the breadth of data being collected and the frequency at which it will be

transmitted from the field to the utility, bandwidth requirements would also be evaluated against expected cost in order to ensure both performance and future compatibility. [17]

Device upgradeability is of crucial importance in ensuring that technology investments stay prudent and true to the overall Smart Grid and Smart Meter objectives. In terms of latency, the tradeoff is between high cost, lower latency systems and lower cost, high latency systems. Evolving requirements surrounding these attributes need to be carefully reviewed and evaluated on an ongoing basis to ensure that technology decisions made are justified.

In addition to these technical attributes, there are some other considerations that relate to evaluating the risk of obsolescence:

- Installed Base – The number of meters that are installed and operational in the field is one of the principle indicators of technology maturity. Scale in terms of installed base could represent both vendor commitment to a product and/or form factor as well as proficiency and availability of product support services and ongoing maintenance. As of 2010, there are approximately 15 million advanced meters in the field which represents about 10% of an estimated 150 million total electric meters in operation. Going forward, installed base forecasts for the U.S. vary widely. However, it can be noted that in programs approved for funding under the American Recovery and Reinvestment Act, over 18 million meters may be installed (pending state regulatory approval). [18]
- Standards – Professional organizations (*e.g.*, NIST, IEEE, EPRI *et. al.*) throughout the Smart Grid industry have been working together to create standards / protocols for infrastructure and applications in order to ensure interoperability. Selecting technology and vendors that submit to these standards that are under development is an important first step toward mitigating some technology risk.
- Vendors – Most Smart Grid technologies are in their early stages of development. Therefore, it is difficult to envision which vendors and products will become the industry leader. Short of deferring all investments in Smart Grid infrastructure until the marketplace becomes more mature, a utility must do its best to evaluate the financial health of vendors, their track record for existing products, and their pipeline for new products. Furthermore, many products in the marketplace today are proprietary and vertically integrated. While these technologies may turn out to be the right choice for the utility and the consumer, the impact of their adoption on the overall risk of obsolescence must be considered before approving any large contract or infrastructure investment.

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[17] "The Smart Grid: Frequently Asked Questions for State Commissions." NARUC, May 2009.

[18] "Progress Report: The Transformation to A Clean Energy Economy." The White House. December 2009.

## 9. THE U.S. DEPARTMENT OF ENERGY MODEL

The relative cost effectiveness by component will likely differ between Smart Meters and Smart Grid. Overall, the principle drivers of cost will be the functionality that is being implemented, the infrastructure and information technology already in place that can be integrated into the proposed solution, and the geographic nature of the specific service territory. As a result, the relative cost effectiveness will likely vary from utility to utility.

Furthermore, as many of these technologies are in their infancy, it is difficult to predict how they will evolve over time in terms of functionality, standards, and overall cost-effectiveness (the latter being a function of marketplace maturity [*e.g.*, number of manufacturers and products, installed base, *etc.*]).

For Smart Meters, the Federal Energy Regulatory Commission (FERC) has published an industry average cost breakdown for Smart Meter solutions that have been implemented and/or proposed. Figure 4 shows that the endpoint hardware constitutes almost half of the total installed cost for Smart Meter systems.

The next largest cost is for building or expanding a communications network to support customer-to-utility data flows. Historically, this cost has represented about 20% of total proposed installed cost. However, if the communications network is expanded to provide for future Smart Grid functionality, significant variance would be expected and would potentially be a result of the specific communications technologies selected, geographic characteristics of the specific service territory, and the pre-existing communications infrastructure that could be leveraged in any network design. More specifically, in its 2010 filing for a Certificate of Public Convenience and Necessity for Smart Grid City, Xcel Energy addressed the wide variance between actual and forecasted costs ($44.8 million actual versus. $15 million initial cost estimate). According to this filing document, Xcel "encountered more complexity in the deployment of the communications infrastructure" than expected and "had to install far more underground fiber than initially projected, substantially increasing the cost associated with the fiber installation."[19]

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[19] Application to the Colorado Public Utility Commission for a Certificate of Public Convenience and Necessity for SmartGridCity, Docket No. 10A-124E, Xcel Energy, March 2010.

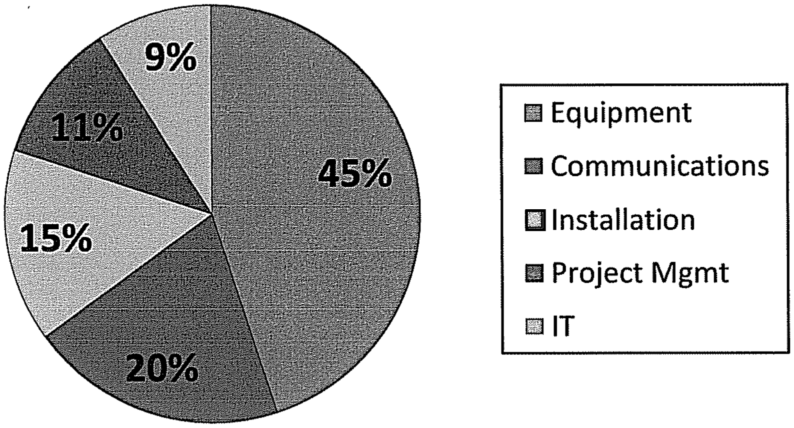

FIGURE 4: AMI SYSTEM COST BREAKDOWN BY KEY COMPONENT[20]

A breakdown of Smart Grid costs is much harder to envision mainly due to the fact that the range of functions that could be implemented would have dramatically different communications requirements. Also, much like Smart Meters, varying geographic and demographic conditions across all service territories (*e.g.*, rural vs. urban) and the distinct attributes and configurations of the many T&D networks across the United States (*e.g.*, varying equipment in use, networked vs. radial configurations, *etc.*) would also drive significant variations. Today, even with federal stimulus money committed to the advancement of advanced distribution automation, there are only a handful of Smart Grid pilots in place. These small scale demonstrations vary significantly in design, functionality, and purpose. Accordingly, it will require added cost and effort to effectively extrapolate and apply lessons, cost estimates, and technical designs to larger scale, more comprehensive Smart Grid programs that will be proposed in the future.

As highlighted by the Commission, the DOE has identified five technologies that will "drive" the Smart Grid:

1. Integrated Communications

The most significant cost of any Smart Grid solution will likely be the cost of building a communications network that can support real-time grid state determination as well as remote and automated controls of field equipment. At a high level, the technology selection and requirements (*e.g.*, bandwidth, latency) for this communications network will depend on the robustness of the functionality that is being implemented and the geographic characteristics of the service territory.

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[20] Pg. 35 "Assessment of Demand Response and Advanced Metering," FERC 2006

2. Sensing and Measurement Technology

Unlike typical Smart Meter solutions where endpoint hardware represents almost 50% of total cost, field equipment for Smart Grid solutions will likely be a less prominent cost component. The first types of field equipment are sensors. These technologies range widely in terms of cost and functionality. They can be basic voltage and current monitoring devices or more sophisticated phase angle measurement devices (*e.g.*, synchro-phasors). In general, the main impact of sensors on total Smart Grid costs would be a reflection of the data management costs required to support these new monitoring points. As a result, key planning decisions (*e.g.*, number of monitoring points per substation or feeder, parameters to be monitored, frequency of data collection) would be principle drivers of the total cost to provide a robust sensor network throughout the transmission and distribution systems.

3. Advanced Components

Again, unlike typical Smart Meter solutions where endpoint hardware represents almost 50% of total cost, field equipment for Smart Grid solutions will likely be a less prominent cost component. The second type of field equipment are the advanced components that will either replace existing equipment or be added new to provide improved visibility or control to system operators. Many of these components are already in the field (*e.g.*, solid state switches; communications-enabled load tap changers, regulators, and capacitors) and have proven operational track records across the United States. In terms of emerging advanced distribution technologies, grid components like superconductors, grid storage technologies, and other power electronics have very limited field testing and incomplete operational track records. This presents clear operational challenges for utilities as well as new reliability risks that must be better understood and mitigated. Furthermore, the cost effectiveness of these components at scale is currently high as most of these technologies are not yet commercial. Depending on their eventual implementation timeline, these components could represent a significant cost depending on the end-state Smart Grid vision and specific functionality being implemented.

4. Advanced Control Methods, Improved Interfaces and Decision Support

As part of a Smart Grid solution, advanced control methods, interfaces, and decision support tools are needed to monitor essential grid components and amplify human decision-making in order to enhance rapid diagnosis of grid events and to determine precise solutions in real time. This represents a dramatic enhancement to current operations. Accordingly, while IT costs represent only 10% of total program cost for typical Smart Meter deployments, they are likely to be a more significant cost, risk, and organizational barrier for utilities that are deploying advanced transmission and distribution automation solutions.

## 10. CONSUMER ATTITUDES AND PREFERENCES TOWARD EIDS AND DR

Demand Response (DR) programs – mainly in the form of direct load control programs and assorted opt-in variable rate structures – have been offered by utilities to various customer segments for decades. Recently, Smart Metering technologies have developed rapidly and are becoming cost effective for more utilities every year. Furthermore, environmental concern and societal pressures have increased the visibility of, and appreciation for, the role demand-side resources can play in both wholesale and retail markets. Accordingly, over the past 5 years or so, utilities have implemented robust demand response pilots with the stated goal of increasing levels of demand reduction and energy efficiency/conservation. Also, third party load aggregators like Enernoc and Comverge have entered the demand response market and been financially successful. Overall, industry support for energy information devices (EIDs) and DR is reflected by these numerous pilot programs, increasing competitive activity, and significant advances in product development by technology vendors.

Across multiple pilots, while the results have varied widely, demand response programs like TOU and CPP have proven effective in reducing peak loads and driving measurable reductions in energy consumption. Map and table of statewide Smart Meter deployments, plans and proposals, as summarized by the Edison Foundation Institute for Electric Efficiency, is attached as Appendix D and for NRECA in Appendix E[21]. However, the results of these pilots are highly dependent on customer demographics, geographic location, and the magnitude of retail electric rates. Furthermore, whether or not customer action during a pilot program is sustainable or can be extrapolated to larger customer populations is unclear at best.

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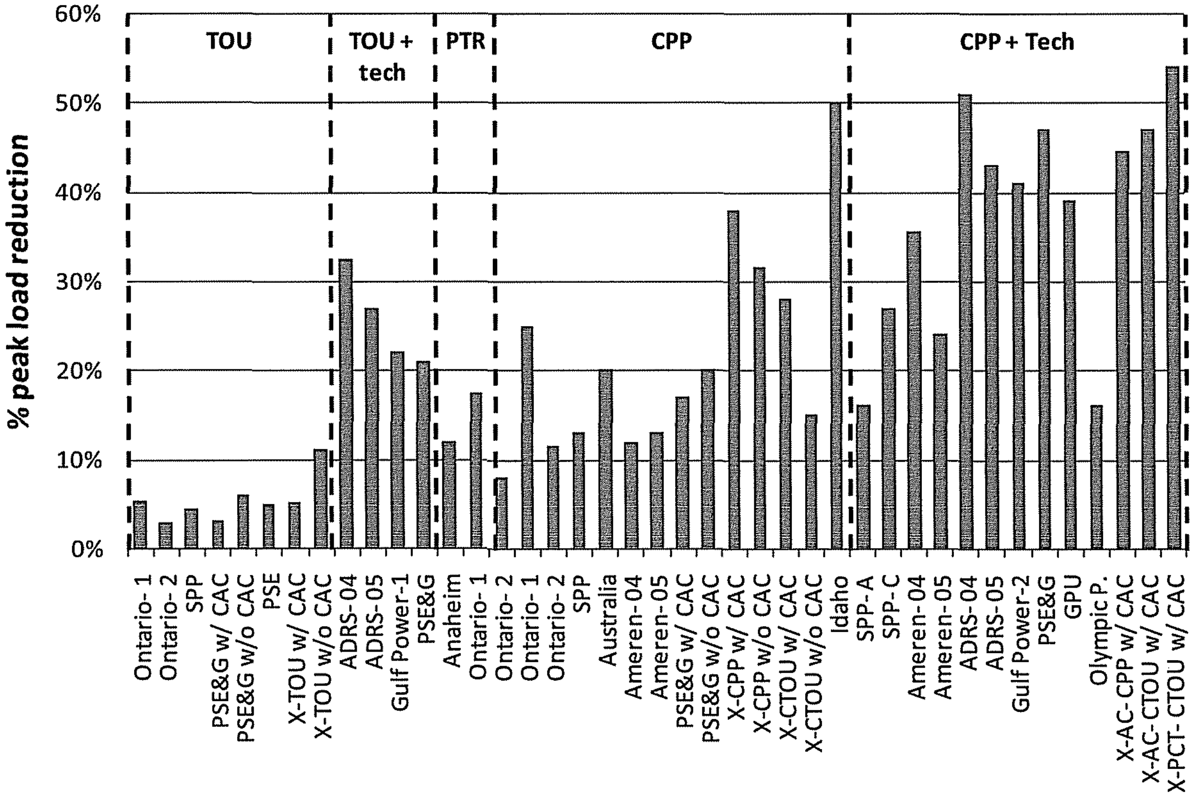
[21] A print out of the website home page is provided in Appendix E. For detailed and interactive information please see http://www.nreca.coop/members/Maps/Pages/SmartGridMap.aspx.

**FIGURE 5: SAMPLE PILOT RESULTS FOR SELECTED TOU AND CPP PROGRAMS, JANUARY 2009**[22]



Even with the apparent success of many of these pilot programs, there are clear reservations throughout the industry when discussing demand response and variable rate structures as a condition of service. First, some prevalent attitudes hold that customers prefer the rate stability that comes with fixed rate structures. These same attitudes hold that the potential cost savings that could be realized by small electric customers could potentially be more than offset by the cost incurred by the utility to offer and support dynamic rate offerings.

Furthermore, when looking at testimony on behalf of the Office of the People's Advocate in Maryland, additional concerns were echoed in an objection to a mandatory time-of-use tariff

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[22] "Household Response to Dynamic Pricing of Electricity – A Survey of the Experimental Evidence." Faruqui, Ahmad and Sanem Sergici, *January 2009. Also*: "Quantifying the Benefits of Dynamic Pricing in the Mass Market." EEI, January 2008.

proposed by BG&E. "The change from a constant per kWh rate for generation costs to a time-varying rate will have the effect of significantly reallocating the cost burdens among residential customers" where burdens would be put on "customers who cannot move usage off those peak periods, including most low-use customers of all incomes." Overall, some of the key reservations with respect to condition-of-service, time-based pricing focused on the need to further study how programs apply differently across customer segments, the need to understand how pilot results can be sustained over time, and the need for more insight into how customers will actually behave in terms of consumption and peak load reductions.[23]

Second, pilot programs focus on very small sample sizes, so it is very difficult to infer what will happen if these types of programs are enlarged. While demand response resources are typically considered to have no incremental variable cost, it is conceivable that beyond a certain tipping point, each additional MW or MWh that the utility would like to reduce would have a very real incremental cost as customers would likely require significant payments when asked to reduce or cut loads that will impact their standard of living (*e.g.*, cycle air conditioners on a hot day, shut off pool pumps during the summer, *etc.*).

Third, the results of these types of programs depends a lot on geographic and demographic attributes that make it difficult to take these pilot results and extrapolate beyond the region in which they were conducted. The average retail rate and the breakdown of consumption by end use both play a significant role in determining the results of any implemented demand-side management program.

Beyond utility-centric demand response, third party service providers like Google and Microsoft are making news as they have begun to offer energy-related products and services. Through products like Microsoft Hohm and Google PowerMeter, some web companies have found ways to provide customers with data and energy services, even without utility data feeds. Whatever the motivation of these companies (*e.g.*, traditional advertising revenue, % of click through sales, demand management charge), the increasing activity in this "beyond-the-meter" space may indicate an increasing customer interest in demand response and EIDs (and other in-home networks / devices). This potential trend is definitely something that the utility industry is monitoring and assessing potential strategic actions in the short term.

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[23] Direct Testimony Of Nancy Brockway On Behalf Of The Maryland Office Of People's Counsel in response to Maryland PUC Case Number 9208. August 2009.

It must also be recognized that some measurable amount of financial reward will be required in order to perk customer interest in demand-side programs. While this threshold of savings is unknown and will likely vary across customer segments, it would be the reward necessary to incentivize customer to take action and become active stewards of their electric consumption.

Overall, customer education across all segments is required if demand response and variable rate structures are to be expanded or made as a condition of service. This education effort would need to focus on both how the programs function and what the potential benefits are to the customer. Furthermore, an emphasis should be placed on how the utility is a partner to the customer in demand-side management, as results could include mutual system-wide improvements to overall cost-effectiveness and reliability of service.

### 11. CONSUMER-ORIENTED APPLICATIONS

There is a considerable range of customer-oriented applications within the Smart Meter / Smart Grid space. They range from technologies or applications whose main purpose is to convey information (*e.g.*, advanced meters, customer web portals) to those that require extensive customer awareness and involvement in order to use (*e.g.*, time- or incentive-based rate structures, home area networks).

Technologies or applications whose main purpose is to convey information can be used on demand by customers with ease. Smart Meter infrastructure can be used by the utility to send notifications that can be used ad hoc by customers to gain insight into outage events or even to facilitate on-/off-peak rate structures like critical peak pricing or peak-time rebates. Also, customer web portals can be used to transmit consumption data to the customer using reports that can be customized to reflect a level of granularity specified by the customer. While these technologies are the simplest for consumers to understand, they also likely would deliver the smallest impact in terms of peak load or energy consumption reductions.

On the other end of the spectrum, customer-oriented applications that increase visibility and provide centralized and coordinated control tools have the potential to be complex but also will likely deliver the most significant reduction in peak load and/or consumption. These include home area networks that would likely be very diverse in terms of their complexity and configurations. Depending on the format, technology vendors could provide tools to automate the optimization of energy consumption. Also, along the lines of traditional utility initiated direct load control programs, there is the potential for a customer to allow the utility to control on-premise loads in order to optimize their energy consumption or the operation of his/her home area network.

Customer-oriented applications vary in complexity and configuration based on customer sector. In-premise devices (*e.g.*, programmable communicating thermostats, in-home energy displays, load control switches) and customer web portals are more likely to be found in the residential and small commercial sectors. By contrast, in the large commercial and industrial sectors, similar but more complex applications have been yielding benefits for many years in the form of energy management systems, remote energy management services, and Internet and standard protocol based process control systems. While these applications differ in function and complexity based on customer class, they serve one same goal which is to communicate data to the customer and/or about the customer.

Again, the increasing complexity and customer involvement in Smart Meter and Smart Grid solutions emphasizes the need to improve customer education and understanding of the many concepts and technologies. Many customer surveys, including one done by the National Rural Electric Cooperative Association (NRECA), indicate that there is no consensus definition of Smart Grid, reveal a diversity of customer interests when it comes to technology, and demonstrate a need to improve overall perception of how the power system works and how improvements will impact / deliver value to the end customer.[24] These findings not only indicate a need for the utility to increase customer awareness, but they also provide a clear opportunity for utilities to demonstrate to customers that they are not just a seller of power but also a partner with a vested interest to help customers improve how they can more efficiently and cost effectively use energy.

Overall, many Smart Grid technologies are merely enablers. Specifically, Smart Meters may enable and enhance many "beyond-the-meter" technologies (*i.e.*, home-area networks) by providing robust integration with utility infrastructure and data. This "beyond-the-meter" space is still in its infancy and it could very well be significant as the market continues to develop and evolve.

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[24] "Smart Grid: Customer Perceptions." NRECA Market Research Services, June 2010, http://www.nreca.coop/presentations/1ABruceBarlowd.pdf, included in Appendix F.

## 12. COST RECOVERY ISSUES AND MECHANISMS

Smart Meter and Smart Grid installations involve the integration of many technology components, require extensive coordination across the utility value chain in order to achieve success, and are very capital intensive. Much like any other deployment of utility capital, cost recovery is an important issue that must be addressed in order to both incentivize all parties to agree to a proposed project as well as to allocate all costs and risks in an equitable manner.

Whether Smart Grid investments are recognized to be different from traditional utility investments or not, acceleration of Smart Grid spending may present financial burdens for utilities, depending on the size, scope, and scale of such investments. For customers, it will be critical for utilities to ensure that the pace of acceleration and scope of deployment does not out-pace the awareness and ability of customers to capture the predicted benefits in a reasonable timeframe.

In order for the Commission to carefully assess Smart Grid proposals and the effects of potential cost recovery policies on utilities and their customers, there are a few key regulatory concepts that should be considered. First, any investment must be deemed appropriate with respect to both the decision to undertake a project (*i.e.*, the underlying rationale used to justify the project) and the implementation process (*i.e.*, it was performed by the utility in a timely and reasonable manner). Second, the proposed infrastructure must be useful with respect to the stated project rationale and there should be some relation between the in-service date and the time at which costs are recovered from customers. Third, the allocation of cost and risk between all stakeholders must be done in an equitable fashion. Fourth, because costs are incurred and benefits are realized at different times, the impact of regulatory lag must be considered, just as it has been with other more traditional utility investments, when analyzing or critiquing the financial justification of any project. This includes both administrative lag (*i.e.*, that which is associated with initiating, deliberating, and finalizing the rate case process) and economic lag (*i.e.*, that which results from the natural intervals between rate cases and how changes to consumption and customer behaviors impact cost recovery between those intervals). Finally, the Commission may want to address how to allocate costs among customer classes and among customers within classes in order to assure that customers are treated in an equitable fashion. [25]

The current regulatory processes, procedures, and environment provide the foundation for both utilities and the commission to assess the effects of Smart Grid and Smart Meter initiatives on utilities and their customers. Existing tools such as the Certificate of Public Convenience and

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[25] Illinois Statewide Smart Grid Collaborative Report. September 2010.

Necessity (CPCN), Integrated Resource Plan (IRP), and Demand Side Management (DSM) programs are currently used to provide the Commission with information. Some of these tools only provide information related to long-term plans while others request Commission approval to give increased certainty on cost recovery prior to incurring costs. New tools or prescriptive mechanisms centering only on Smart Meter and/or Smart Grid deployments are not necessary. The Commission should not require a mandatory CPCN or work plan for Smart Grid and/or Smart Meter deployments.

Decisions to invest are made on the available information at the time of the investment decision. However, when emerging technology is implemented and fails to deliver the degree of benefits originally identified, the original investment decision and subsequent allowance of recovery should not be reversed or changed if they were prudent at the time the decision was made. Revisiting earlier investment and recovery decisions can result in regulatory uncertainty which potentially causes utilities to entrench into risk free investments.

Cost recovery mechanisms observed across the utility industry range from base rate treatment of utility capital expenditures to other types of rider mechanisms that include trackers and surcharges.

**Base Rate** – Treating Smart Meter and Smart Grid capital expenditures in a similar manner as any other utility capital investment incentivizes the utility to minimize costs, execute efficient implementation plans, and reduce costs associated with stranded assets (i.e. assets that are retired before they reach the end of their useful life). Base rate treatment also preserves test year matching of expenses and income which would help prevent burdening customers with excessive rates.

**Riders (e.g. trackers, surcharges)** – A mechanism that attempts to track unpredictable cost or significant costs associated with specific projects that are incurred by the utility. These are per customer charges that are based on a test year as well as forecasted program costs and O&M impacts. Typically, these are customer charges that are set by the utility commission during traditional rate cases, require periodic performance reporting by the utility on costs and benefits, and allow for adjustments to be made during ensuing rate cases. However, riders have also been paired with periodic true-up processes that allow for adjustments to be made to cost recovery between test years in order to both insure prudent cost recovery for utilities and protect customers from being over charged if actual costs are below forecasts.[26]

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[26] Another option is for costs associated with Smart Meter and Smart Grid programs to flow through the DSM surcharge in accordance with KRS 278.285 which is described in more detail under Section 20.

Overall, Figure 6 below provides a summary of some of the basic arguments used to support either base rate treatment or the use of a rider mechanism.

**FIGURE 6: SUMMARY OF ARGUMENTS USED TO SUPPORT DIFFERENT COST RECOVERY METHODS**[27]

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

In addition, there are many other issues involved when designing cost recovery mechanisms for Smart Grid projects and when considering whether or not it is appropriate to incentivize the large-scale replacements of existing assets with new and emerging technologies. Some of these issues include:

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[27] Illinois Statewide Smart Grid Collaborative Report. September 2010.

- **Large-Scale Capital Projects** – Smart Grid investments may be large in which case base rate treatment may strain cash flow. Utilities may be confronted with more risk if recovery of Smart Grid investment is not assured, which could raise the cost of capital faced by the utilities and ultimately paid by customers.

- **Capital Scarcity** – Capital is scarce for utilities and Smart Grid projects are competing for dollars along with traditional utility investments in environmental compliance, maintenance and new construction of T&D and generation assets. Tracking mechanisms and surcharges that guarantee prudent capital recovery could help Smart Grid projects win capital dollars that would otherwise have been used for other projects.

- **Depreciation Life** – Many Smart Grid technologies are immature or in the early stages of commercialization. Even many meter technologies that are considered to be mature have only been in the field for a short period of time (10 years or less). Accordingly, assumptions around useful asset lives – which are key inputs into rate design – introduce varying levels of technology risk.

- **Stranded Assets** – Universal deployment of assets, including meters and other distribution equipment, will most likely require the retirement of many assets that still are being paid for by the consumer. Accordingly, any Smart Meter or Smart Grid proposal must attempt to design implementation schedules that fully take into account these stranded costs. In addition, once the equipment is removed from service, these proposals must also address how these stranded costs are to be charged to customers and how these added costs impact the overall project cost effectiveness.

Unlike more traditional utility capital deployments, but not unlike some past utility investments in what were at the time new technologies (*e.g.*, selective catalytic reduction (SCR), flue gas desulfurization (FGD), automated meter reading (AMR)), Smart Grid investments are subject to higher levels of risk due to technology immaturity – both efficacy of functionality and how equipment will perform over time. Investments in Smart Meter and Smart Grid are designed to achieve demand reductions, energy savings, and enhanced customer interaction through improved utility operations and enabled customer consumption reductions. This section references several recovery mechanisms. The National Association of Regulatory Utility Commissioners is contemplating a resolution which, in part, "….recommends that commissions seeking to facilitate deployment of cost-effective AMI technologies consider providing for timely cost recovery of prudently incurred AMI expenditures, including accelerated recovery of investment in existing metering infrastructure, in order to provide cash flow to help finance new

AMI deployment."[28] For utilities who have implemented a DSM recovery mechanism, this existing mechanism is an appropriate means to recover both O&M and capital components of these utility investments, providing for both timely and accelerated recovery which could improve cash flow and help finance further Smart Grid and Smart Meter investment. For those utilities who have not implemented a DSM mechanism, inclusion in standard rate making proceedings would provide cost recovery.

### 13. CYBER SECURITY ISSUES

National Institute of Standards and Technology (NIST) defines cyber security as something that encompasses "measures to ensure the confidentiality, integrity and availability of the electronic information communication systems and the control systems necessary for the management, operation, and protection of the Smart Grid's energy, information technology, and telecommunications infrastructures."[29]

Some of the specific barriers that must be addressed to achieve a secure Smart Grid include but are not limited to [30]

- Incomplete understanding of threats, vulnerabilities, and consequences – A standard approach is needed to conduct vulnerability and risk assessments, to understand the consequences of security threats, and to properly assess the value of potential security upgrades.
- Smart Grid investments and the associated cyber security improvements should be justified through a cost-benefit analysis – Current estimates of the costs for Smart Grid investments and any resulting cyber security investments are high. To justify these high costs, it is necessary to compare them to all of the expected benefits of those investments, including the avoided cost associated with a potential grid security event.
- Increasing use of open systems – Open communication and operating systems are flexible, less costly, and improve system performance, but may not be as secure as proprietary systems.

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[28] http://www.naruc.org/Resolutions/res.to.remove.regulatory.barriers.to.the.broad.implementation.of.advanced.metering.infrastructure.pdf

[29] "NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0." NIST, January 2010

[30] "Smart Grid Principal Characteristics: Operates Resiliently Against Attack And Natural Disaster." Developed for the DOE by the National Energy Technology Laboratory (NETL), September 2009.

- Increasing number of grid participants – As more and more entities participate in the electric system, cyber security issues will become increasingly complex and costly to analyze and manage.
- Difficulty in recovering costs – Similar to other investments in Smart Meters and Smart Grid, there is only incomplete information with respect to the costs and benefits of investments in cyber security infrastructure. Metrics and/or indices, as well as an understanding of investments and results in other jurisdictions, are required to properly assess program costs and design cost recovery mechanisms that allow for the timely recovery of costs prudently incurred by utilities.

As expected, there are currently large investments and robust collaborative efforts underway looking at all issues surrounding cyber security. Overall, NIST is leading the initiative for defining standards needed for designing and implementing 'smart' technologies. While work is ongoing, cyber security strategies, logical architectures and interfaces, and high-level security requirements have been outlined most recently in the document "Guidelines for Smart Grid Cyber Security: Vol. 1, Smart Grid Cyber Security Strategy, Architecture, and High-Level Requirements," published by NIST in August of 2010.

Also, the DOE has designated NERC as the electricity sector coordinator for critical infrastructure protection (CIP). While these standards are specifically being considered and developed for the bulk power system, there are clear applications of NERC CIP standards to Smart Meters and Smart Grid implementations. For example, CIP-002-3 calls for utilities to "identify and document Critical Assets through the application of a risk-based assessment."[31] Also, CIP-005-2a requires "the identification and protection of the Electronic Security Perimeter(s) inside which all Critical Cyber Assets reside, as well as all access points on the perimeter."[32] The industry is currently developing perspectives on how these security standards (and others) can and should be applied to the distribution grid and metering infrastructure with consideration being given to technology requirements and total cost.

Some other cyber security issues worth mentioning and discussing include:

- Threat Posed by Increased Number of Network Entry Points / Network-Connected Devices – While measurement points throughout the T&D system are also of concern, Smart Meter

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[31] Requirements from NERC CIP-002-3 "Cyber Security — Critical Cyber Asset Identification" approved December 2009.

[32] Requirements from NERC CIP-005-2a "Cyber Security — Electronic Security Perimeter(s)" adopted February 2010.

deployments could pose a more significant cyber security threat. Some recent analysis has focused on methods for attacking wireless devices used in AMI networks that are connected to Smart Meters, are located on customers' premises, and are therefore outside the utility's physical security perimeter. Attackers can extract data (*e.g.*, network authentication keys) from the memory of these devices to gain network access and potentially compromise direct control systems.[33]

- Data Privacy Concerns – Data that is mismanaged by the utility poses a direct threat to electric customers and as a result, ensuring data security and data privacy is a core issue for all Smart Meter and Smart Grid proposals. Keys to determining how to manage customer privacy issues include defining data ownership, ensuring customer awareness with respect to types of data being recording and their specific uses (including sharing with 3rd parties), defining and protecting data that is stored, and ensuring effective and secure data disposal.[34] Data privacy issues are discussed further in section 16. Utility Usage Data and Meter Access.
- Use of Public Communications Infrastructure / Networks – The utility industry is one that has historically relied almost completely on private networks for their communications needs. This is especially true when dealing with mission critical data flows (*i.e.*, those required to keep the lights on). Many proposed Smart Grid networks recommend leveraging 3rd party communications networks to reduce upfront costs and capital risks that would otherwise be borne by the utility and the customer. This has introduced many security concerns and potential threats that are being currently studied and addressed across the industry by NIST and others.
- Operational Technology vs. Information Technology – Over the last few years since the focus on Smart Grid has intensified, the lines are becoming increasingly blurry between operational technology (OT) and information technology (IT). Other than managing potential organizational changes, some key challenges involve:
    - Using the same network and infrastructure to manage both mission critical data and activity (*i.e.*, those required to keep the lights on) as well as those that are business critical (*i.e.*, billing and other customer relationship management activities that would be supported by an AMI solution) introduces a key issue of network traffic segmentation that must be properly addressed to comply with emerging cyber security standards and protocols being developed by NIST and other industry participants;

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[33] "Study of Security Attributes of Smart Grid Systems – Current Cyber Security Issues." DOE, April 2009.

[34] "Privacy of Consumer Information and Devices in the Electric Power Industry." Prepared for GridWise Architecture Council & NIST, October 2009

- Consolidating and coordinating data flows across multiple networks (*e.g.*, AMI, SCADA, distribution automation beyond the substation, corporate networks) that handle traffic that can be both operational (OT) and informational (IT); and
- Providing network resiliency which includes both ensuring network availability and providing fast rerouting capabilities to support high-priority network traffic.

Overall, standards are evolving quickly as a result of significant investments of time and capital across the industry. While it is important for utilities and the Commission to monitor developments with respect to cyber security, it is just as important for the Kentucky utility industry to continue playing an active role in the work being performed by NIST and others across the United States.

### 14. FUTURE TECHNOLOGY AND OVERALL ADAPTABILITY

Because the Smart Grid industry is rapidly evolving, it would be difficult and potentially not prudent to identify "plug and play" standards. Instead, the Commission should allow market conditions (*e.g.*, evolving requirements and standards) to continue enabling the plug and play philosophy. As the Commission is aware, there are many industry organizations working in concert to develop national standards and protocols. Accordingly, the Kentucky Commission should avoid identifying any Kentucky-specific standards so as to eliminate any compatibility risks. Overall, utilities across the United States have unique systems and a wide range of "legacy" applications that will likely make Smart Grid solutions highly customized across the industry. Due to the potential for a wide range of solutions across even a single service territory, the Commission should be very concerned with creating an upfront framework for evaluating potential impacts on reliability, the customer experience, and expected cost effectiveness of any proposed Smart Meter / Smart Grid proposal.

### 15. HOME AREA NETWORK (HAN) PROTOCOLS

Home area networks can be implemented by customers, to varying degrees, with or without participation from the utility. These systems involve many technology components:

- <u>In-home display/controller</u> – the central interface for the customer to visualize and control energy usage throughout the home, this could also be the gateway into the home for the utility (if the Smart Meter has HAN communications capabilities);
- <u>In-home control devices</u> – smart thermostats, load control switches that would communicate with the in-home display/controller to allow the customer to control specific appliances and devices throughout the home;
- <u>Smart meters (optional)</u> – could be integrated with HANs to provide communications capabilities to a customer's in-home devices; this would potentially allow the customer to

provide granular end-use data to the utility and could also allow the utility to communicate and control in-home appliances and devices if requested by the customer

- Granular energy use data (optional) – data provided by the utility to the customer would provide the customer with a frame of reference (*e.g.*, historical usage, peer comparison) when managing their consumption; data could also be gathered and maintained by the customer at the customer premise using customer owned equipment;.
- Customer portal (optional) – A web-based interface managed by the utility that consolidates and provides a full suite of energy management tools to customers.

There are many standards and products in the marketplace. Currently, ZigBee is considered a prevalent standard for HAN device communication.[35] The ZigBee Alliance maintains a set of specifications, based on the IEEE 802.15.4 standard, to ensure interoperability between a wide range of products using wireless communications.

By ensuring that smart meters are ZigBee-enabled, two-way communication would be provided from the utility through the Smart Meter and to demand response devices on the customer's premises. Additionally, ZigBee-enabled, in-home displays could be installed so that a customer could view historical billing data, view current energy usage, and monitor energy prices in real-time.

By adopting a standard such as ZigBee, a utility would create a platform where other innovative ZigBee-enabled products could be added to further expand the customer's ability to manage their energy use. Furthermore, this could also reduce overall costs as the adoption of a singular standard would potentially reduce the complexity of implementing and integrating home area networks. From a risk perspective, however, this would maximize technology risk as the emergence of another standard would increase the potential cost of obsolescence.

Many HAN technologies are in the pilot stage and the marketplace is accordingly very immature. Despite ZigBee being named by NIST as a prevalent standard for home area networking (along with Z-Wave), it is likely premature for the Commission to be specifying HAN protocols.[36] Between now and the time when an actionable perspective is developed in Kentucky with respect to HAN, countless technological, regulatory, and customer drivers will impact a marketplace that is already volatile. Accordingly, it is likely that multiple HAN standards will be adopted across

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[35] As noted later in this response, it would be premature for the Commission to specify any HAN protocol. ZigBee references used in the document are for illustrative and discussion purposes only.

[36] "NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 1.0." NIST, January 2010

the marketplace. As a result, each utility should prepare strategies for integrating these multiple standards and technologies into the Smart Grid. While this could increase total integration and implementation costs, it would minimize exposure to technology risks in this constantly evolving industry.

In short, the Commission should consider the following with respect to home area networks:

- While official support for HANs can be considered at a later date, to the extent possible, Smart Meter projects should provide for the capability of being connected to devices in the home. Specific communications chips can be implemented either when the Smart Meter is installed or at a later date.[37] Regardless, this functionality would be critical for customers who are trying to implement robust in-home energy management systems (with or without utility involvement);
- Regulatory standards and minimum requirements are premature as HAN products (and the overall HAN marketplace) are still evolving;
- Multiple HAN protocols will likely be adopted across Kentucky and, therefore, the focus should be on ensuring their compatibility with any proposed Smart Meter or Smart Grid infrastructure; and
- Regardless of type or frequency, granular energy use data should be provided to customers using multiple channels (Smart Meters, EIDs, web portals, *etc.*) to ensure universal coverage and availability of information across the service territory and to all customer segments.

## 16. UTILITY USAGE DATA AND METER ACCESS

### Data Acquisition

By default, utilities will collect energy usage data which at a minimum will be used for customer billing. In addition, the Smart Meter system will enable utilities to capture meter specific data such as voltage and power quality readings, meter event data, and acknowledgements and verifications of message transmissions or price signals/compliance.

### Establishing Meter Data Specifications

The management, usage, and protection of meter data are key considerations for the planning and design of Smart Meter solutions. Specifications, like what type of data to gather and the interval for data gathering, will ultimately depend on the actual Smart Meter functionality being implemented (*i.e.*, basic Smart Meter system, advanced Smart Meter system with a variable rate

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[37] Adding communications chips during initial meter installation would require knowing what communication protocols would be required in the future, which could be difficult to determine. Installation of communications chips at a later time could require the removal of the meter to perform the upgrade and may be cost prohibitive.

structure as condition of service). Also, just as important is the infrastructure that would be specified as part of a proposed Smart Meter solution (*e.g.*, advanced meters, collectors, head-end, meter data management systems, and data warehousing). The integration of these components will be critical to protecting sensitive customer data and ensuring data quality.

Overall, it is too early to set definitive meter data specifications or to define data management infrastructure requirements, as both are highly dependent on the level of Smart Meter functionality being implemented. The Commission must also take into consideration what Smart Metering infrastructure has already been deployed in Kentucky when establishing any minimum requirements. Furthermore, data requirements need to align with a utility's rate structure. It is important to note that these specific requirements are not being recommended; rather, any minimum requirements should reflect technology developments as well as any additional insight that might be gained into customer preferences or requirements.

Data Validation

There is a balance between mandating data quality and validation processes, and the ability for the utility to deliver data to the customer in near real-time. The need for data validation standards should be different depending on the specific data type. There are two general types of data: 1) data used to support customer billing; and 2) data provided to customers to enhance visibility of energy consumption and improve participation in demand side programs. The latter likely wouldn't need as much validation as the priority for this data is to deliver it in a timely manner. However, data used for customer billing requires extensive validation. New Smart Meter capabilities could improve overall billing accuracy (*e.g.*, reduced or eliminated bill estimation, manual meter reads, and human error).

Data Storage

While current Smart Meter technologies support storage of meter read data locally at the meter, when considering requirements with respect to this parameter, the Commission should take into consideration the Smart Meter technologies already deployed in Kentucky. No matter the specification, the overall goal is to guarantee adequate data backup and quality while also being mindful that additional requirements will drive increased data management costs.

Other state commissions have handled this issue in a variety of ways. For example, in Maryland, the Commission has defined a minimum requirement that "all meters shall have a minimum of 14 days of data storage capability on the meter."[38] On the other hand, Pennsylvania was less

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[38] Order No. 81637 in Case No. 9111. Public Service Commission of Maryland, September 2007.

specific. Rather than reference a specific number of days, the Commission has stated that all "smart meter plans [should] incorporate provisions ensuring that all billing data is retrieved before data is overwritten and recoverable following communications outages" in addition to a requirement that "on board meter storage of meter data [should] comply with nationally recognized non-proprietary standards such as ANSI C12.19 and C12.22 tables."[39] The citations to the Maryland and Pennsylvania decisions are provided for illustrative purposes only and should not be viewed as a recommendation for Kentucky.

### Customer Data Access

To ensure fairness and to maximize the efficacy of demand-side programs, the utility should provide data using as many channels as needed in order to satisfy industry recognized standards or requirements that may be set by the Commission. Accordingly, a combination of notifications via a Smart Meter, web-based portals, data transmittal through HAN devices, and even physical mailings could be used to provide customer access to both billing and consumption data at varying frequencies depending on the medium.

### Authorized Third Party Data Access

The Commission's questions concerning the transmittal of customer data to authorized third parties emphasizes the need to establish guidelines and methods for handling customer data so that customers are fully aware of who is using the data and for what purpose the data are being used. In other markets across the United States, this is sometimes done using a web portal or a simple release form submitted by the customer to the utility. Regardless of the method, which could be made more secure depending on the privacy concern, the utility must establish clear procedures for customers who are trying to release their energy data to third parties. It is also important to create a standard for what data and in what form data is released, so that data needs associated with specific customers and third parties do not force the utility to bear additional costs.

### Data Privacy

An additional concern not specifically raised by the Commission is data privacy. Data that is mismanaged may pose a direct threat to electric customers and, as a result, data security and data privacy are core issues for all Smart Meter and Smart Grid proposals. Keys to determining how to manage customer privacy issues include defining data ownership, ensuring customer awareness with respect to types of data being recorded and their specific uses (including sharing

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[39] "Smart Meter Procurement and Installation Implementation Order," Docket No. M 2009 2092655. Pennsylvania Public Utility Commission, June 2009.

with 3rd parties), defining and protecting data that is stored, and ensuring effective and secure data disposal.[40]

Utility metering infrastructure is designed to collect data for both utility and customer use, such as billing, usage presentment, capacity planning, etc. While the customer has access to their data and can request that their data be provided to others, utilities should implement processes that do not release personally identifiable data without the customer's required consent. The utility will possess and maintain the data and is free to use customer data within the confines of promulgated utility affiliate transaction rules, state and federal laws.

### 17. METER TO EDC COMMUNICATIONS

Communications technology is a primary component of any Smart Meter or Smart Grid system. There are two distinct communications solutions needed. The first is the backhaul or wide area network (WAN) solution that connects the collectors to the head-end system. The second is the local area network, or LAN, that provides connectivity between the collectors and meters.

Each of these solutions could be satisfied with different technologies depending on network design, solution requirements, and cost assessments of the various alternatives. The selection of communications technology has a variety of guidelines which include, but are not limited to, the following:

- Bandwidth (both burst and sustained throughput) and latency necessary to handle proposed system requirements (*e.g.*, interval of meter reads, dynamic pricing programs that must be supported);
- Compatibility with the selected metering technology as well as potential transmission and distribution automation technologies;
- Designed with key demographic considerations (*e.g.*, types of customers, population density, geographic terrain, *etc.*) in mind;
- Leveraging existing communications infrastructure – both utility-owned and infrastructure available through third parties – to create an integrated and redundant network; and
- Modular and scalable in its design so as to minimize stranded assets and ensure forward compatibility with any future Smart Grid enhancements or implementations.

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[40] "Privacy of Consumer Information and Devices in the Electric Power Industry." Prepared for GridWise Architecture Council & NIST, October 2009

Overall, there are many bidirectional communications media available to support Smart Meters and Smart Grid solutions. Figure 7 provides a relative assessment of the characteristics of some communications technologies available in the market today.

FIGURE 7: RELATIVE COMPARISON OF SMART GRID COMMUNICATIONS TECHNOLOGIES[41]

| Technology | Bandwidth | Latency (Amount/Variability) | Reliability | Security | Upfront Cost | Ongoing Cost |
|---|---|---|---|---|---|---|
| Leased Lines | Low | Low/Low | Medium - High | Medium | Low | High |
| Wired Broadband | Medium - High | Low/Low | Medium | Medium | High | Medium |
| Private Fiber | High | Low/Low | High | High | High | High |
| Narrowband PLC | Low | Medium/Medium | Medium | Medium | High | Low |
| BPL Medium | Medium - High | Medium/Medium | Medium | High | High | Medium |
| RF Mesh | Low | High/High | Medium | Medium | Low | Low |
| Metro Wi-Fi Mesh | Medium - High | Medium/High | Medium - High | High | Low | Low |
| Private RF Pt-to-MPt | Low | Medium/Medium | Medium | High | Medium | Low |
| Private WiMAX | Medium - High | Medium/Medium | Medium | High | Medium | Medium |
| 2G/3G Cellular | Low | Medium/Medium | Medium | Medium | Medium | Medium |
| 4G Cellular | Medium - High | Medium/Medium | Medium - High | Medium | Medium | Medium |
| VSAT Satellite | Low - Medium - High | High/Medium | Medium - High | High | Low | High |

In addition to characteristics noted above, utilities must take into consideration availability and coverage pertinent to specific communications technology. Availability and coverage could be largely dependent on utility specific geography which could prove to be the key deciding factor in the meter to EDC communications selection process.

In terms of protocols, there is a strong industry push towards IP-based communications. What is unclear, however, is the scalability of this protocol if extended down to the individual meter, as this would imply that all monitoring and control points would have their own IP address. When looking at Smart Meters in the current marketplace, first movers typically leverage a private network and proprietary communications protocols to manage the collection and transmittal of data gathered from the meter end points. These options have obvious limitations in terms of interoperability and while unit costs have become attractive in recent years, performance track records are no more convincing than other less mature communications solutions.

No matter how the industry landscape develops, utilities are exploring hybrid solutions to support their future Smart Meter and Smart Grid plans. These hybrid solutions will likely use

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[41] "Smart Grid Communications: Overview of Smart Grid Communications Requirements, Technologies, and Market Issues." Pike Research, Q3 2010. Also, for relative cost assessments: Accenture analysis of technical documents, vendor presentations, and Commission filing documents across the United States.

different technologies for the backhaul and the local area network (LAN) because different requirements for the backhaul and the LAN will impact technology selection for each. Second, there is the potential for integrating a utility's existing communications infrastructure into the Smart Grid backhaul solution in order to reduce total installation costs. Third, varying geographic conditions of the service territory will impact both requirements and relative cost effectiveness of specific technologies. Overall, the likelihood of hybrid solutions that consist of incompatible technologies makes it prudent for any communications management system to be characterized by openness, standardization, and interoperability.

While IP-based management systems are one choice that satisfy these requirements, it is the position of this paper that the Commission should reference work being done by the NIST who, under the EISA 2007, was assigned the "primary responsibility to coordinate the development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems."[42] As part of this effort, NIST has been working collaboratively across the industry to identify interoperability standards and build use cases for all Smart Grid functions.[43]

### 18. ACCESS TO PRICE INFORMATION

The manner in which the customer should be provided pricing information depends on a variety of things:

- What type of infrastructure is in place (*e.g.*, Smart Meters, Customer Portal, communications capabilities directly with home area networks that are owned and operated by the customer, *etc.*);
- What programs the pricing information is meant to support (*e.g.*, time of use rates, critical peak pricing, real-time pricing);
- What type of pricing data is being made available (*e.g.*, off peak, on peak, interval);
- What other data is being provided to the customer on an interval basis and for what purpose; and
- An assessment of customer needs with respect to energy information – is it supporting HANs, integration of PHEVs, customer-owned and -operated distributed generation (including photovoltaics).

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[42] Pg 296. The Energy Independence and Security Act of 2007

[43] http://collaborate.nist.gov/twiki-sggrid/bin/view/SmartGrid/IKBUseCases

As stated earlier, multiple communications channels would likely need to be provided and supported by the utility to ensure universal access criteria and requirements set forth by the Commission. This would be because not all customers have internet access and home area networks will most likely not be mandatory for all customers. While it is difficult to forecast, a combination of three mediums would likely be a part of any future solution:

- Leveraging advanced meter to support proactive notification capabilities (from utility to the customer);
- In-home displays as a part of HAN or other Smart Meter technology for the utility to provide consumption data and alerts to customer; and
- Secure websites or customer portals – which are currently being used in the industry across the United States – to provide customers with access to their billing information, consumption data, as well as forward pricing that could be used to optimize participation in demand side management programs, if any.

With respect to defining minimum requirements, the Commission should consider setting minimum requirements but must take care to ensure they are in sync with Kentucky's broader Smart Meter / Smart Grid vision. At such an early stage and without more specific guidance from the Commission, it would be difficult to prescribe requirements for parameters like the type of information being provided and the frequency at which it should be provided.

In terms of establishing a standard format for presenting price information to customers, it is also too early to do this without interfering with the competitive process in the marketplace. Standardization at such an early stage could impede the development of innovative products and services. Furthermore, surveys have shown, not surprisingly, significant variations in customer preferences across customer segments with respect to in home display technologies and options.[44]

### 19. AUTOMATIC CONTROL

Smart Meters by themselves do not provide capabilities for the automatic control of electricity consumption. However, Smart Meters are a foundational technology that would support many other technologies and programs that could be used by consumers, the utility, and other parties to control consumption. Furthermore, depending on the configuration, they could be used as the gateway into the home which would provide functions to interconnect the Smart Meter network and the home area network. According to the international standard ISO/IEC 15045-1 (A Residential gateway model for Home Electronic Systems), "the responsibilities of the gateway

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[44] "Smart Grid: Customer Perceptions." NRECA Market Research Services, June 2010, Appendix F.

include protocol translation and provisions for ensuring the privacy, safety, and security of consumers."[45]

The following key technologies and programs, coupled with Smart Meters, could support automatic control of customers' energy consumption:

Direct Load Control Program – legacy programs where the utility pays the consumer for the right to control specific customer loads (*e.g.*, air conditioning, water heaters, pool pumps, *etc.*) during critical peak periods → Smart Meters could provide communications with in-home load control devices so that the utility can more effectively and efficiently manage and monitor a large-scale program of this type.

Home Area Networks – coordinated network of devices and information technology on the customer's premises aimed at increasing customer awareness and providing tools for the centralized control of energy consumption → Smart Meters could be the gateway between the utility and the customer to manage data flows and potential utility actions that are authorized by the end consumer.

Electric Vehicle Charging – an emerging concern of utilities is to be able to support and potentially control the charging of electric vehicles → Smart Meters could be integrated with charging equipment in order to provide intelligence (*i.e.*, Smart Charging) that would balance the charging requirements of customer with the utility's concerns over preserving reliability and maintaining grid stability.

In terms of specifying smart metering protocols and communication media needed to implement automated controls, it is too early to select such protocols and media without concrete industry standards in place. The industry should be allowed to define appropriate standards.

## 20. ACCELERATING SMART METERING DEPLOYMENT

Any plan to accelerate Smart Meter investments must fully consider the trade-offs with respect to accelerated delivery of benefits versus technology risk (*i.e.*, functionality is expanding and technology costs are declining over time). Furthermore, the decision to provide incentives should be based on an agreement between the Commission and the broader utility industry in Kentucky on the benefits of Smart Meters, how Smart Meters will impact / improve the entire utility value

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[45] "Home-to-Grid Domain Expert Working Group – Requirements." GridWise Architecture Council / NIST, August 2009

chain, and the role of Smart Meters as a foundational solution for modernizing the electric grid in the state.

If the Commission does decide to incent investments in Smart Meters, it should first thoroughly assess the costs and benefits of a proposed solution. Secondly, the Commission should provide a mechanism for utilities to recover prudently incurred costs in a timely manner. KRS 278.285(1)(h) provides that "Next-generation residential utility meters that can provide residents with amount of current utility usage, its cost, and can be capable of being read by the utility either remotely or from the exterior of the home" may be utilized within the existing utility DSM mechanism.

## 21. BEST PRACTICES, LESSONS LEARNED, AND RECOMMENDATIONS

1. Case No. 2008-00408 was established by the Commission to review standards of the Energy Independence and Security Act of 2007 ("EISA 2007"), part of which amended the Public Utility Regulatory Policies Act of 1978 ("PURPA"). The Commission was to determine whether or not to implement four new PURPA standards and one non-PURPA standard applicable to electric utilities and two new PURPA standards applicable to gas utilities. The parties of record recommend that the Commission should not adopt any of these standards, or any variation thereof.

2. Pilots and trials built to understand customer behavior (*i.e.,* acceptance, use, sustainability of savings, etc.) and investigate emerging technology integration into existing infrastructure should be continued.

3. Customer education about the benefits of energy efficiency and specifically smart technology is critical to gaining consumer acceptance and employment of this technology. Consequently, continued and new efforts focused on customer education should be embraced by the Commission.

4. Resist the urge to implement prescriptive requirements for smart technology deployment.

5. The case participants recommend that this report conclude Case No. 2008-00408.

The Attorney General's Office, along with Community Action Council, provided comments and recommendations to the draft report. The Attorney General's Office and the Community Action Council will be filing comments separately in this proceeding.

# APPENDIX A: ACRONYMS AND ABBREVIATIONS

## Acronyms and Abbreviations

| | |
|---|---|
| AMI | advanced metering infrastructure |
| AMR | automated meter reading |
| ANSI | American National Standards Institute |
| BG&E | Baltimore Gas & Electric |
| BPL | broadband over power line |
| CAIDI | Customer Average Interruption Duration Index |
| CIP | critical infrastructure protection |
| CPCN | Certificate of Public Convenience and Necessity |
| CPP | critical peak pricing |
| DA | distribution automation |
| DER | distributed energy resources |
| DG | distributed generation |
| DMS | distribution management system |
| DOE | Department of Energy |
| DR | demand response |
| DSM | demand side management |
| EDC | electric distribution company |
| EE | energy efficiency |
| EIA | Energy Information Administration |
| EID | energy information device |
| EISA | Energy Independence and Security Act |
| EMS | energy management system |
| EPA | Environmental Protection Agency |
| EPAct | Energy Policy Act |
| EPRI | Electric Power Research Institute |

| | |
|---|---|
| EV | electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| FGD | flue gas desulfurization |
| GIS | geographic information system |
| HAN | home area network |
| IEC | International Electrotechnical Commission |
| IED | intelligent electronic device |
| IEEE | Institute of Electrical and Electronic Engineers |
| IOU | investor-owned utilities |
| IP | internet protocol |
| IRP | Integrated Resource Plan |
| ISO | independent system operator |
| ISO | International Organization for Standardization |
| IT | information technology |
| KRS | Kentucky Revised Statutes |
| KVAR | kilovolt-ampere reactive |
| kWh | kilowatt-hours |
| LAN | local area network |
| MDMS | meter data management system |
| MW | megawatts |
| MWh | megawatt-hours |
| NARUC | National Association of Regulatory Commissioners |
| NERC | North American Electric Reliability Corporation |
| NETL | National Energy Technology Laboratory |
| NIST | National Institute of Standards and Technology |
| NPV | net present value |

| | |
|---|---|
| NRECA | National Rural Electric Cooperative Association |
| O&M | operations and maintenance |
| OMS | outage management system |
| OT | operational technology |
| PHEV | plug-in hybrid electric vehicles |
| PJM | Pennsylvania, Jersey, Maryland, Power Pool |
| PLC | power line communication/power line carrier |
| PQ | power quality |
| PSC | public service commission |
| Pt-to-MPt | point-to-multipoint |
| PTR | peak time rebates |
| PUC | public utility commission |
| RF | radio frequency |
| RFP | request for proposal |
| RTO | regional transmission operator |
| RTP | real-time pricing |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SCADA | supervisory control and data acquisition |
| SCR | selective catalytic reduction |
| T&D | transmission and distribution |
| TA | transmission automation |
| TCP | transmission control protocol |
| TOD | time-of-day pricing |
| TOU | time-of-use pricing |
| TRC | total resource cost test |

| | |
|---|---|
| VAR | volt-ampere reactive |
| VSAT | Very Small Aperture Terminal |
| WAN | wide area network |
| WiMAX | Worldwide Interoperability for Microwave Access |

# APPENDIX B: PRICING RATE STRUCTURE

## Pricing Rate Structures

Dynamic pricing refers to pricing that varies according to the time at which the energy is used. It is normally tied directly or indirectly to prices in the wholesale market or to system conditions (peaks) and normally is delivered to the customer via time-based rates or tariffs. Types include Time-of-Use or Time-of-Day Pricing, Critical Peak Pricing and Real-Time Pricing.

Time-of-use (TOU) or time-of-day (TOD) rates are energy prices that are set for a specific time period(s) on an advance or forward basis, typically not changing more often than twice a year (summer and winter season). Prices paid for energy consumed during these periods are pre-defined and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period, or reducing consumption overall. These pre-defined time periods typically include from two to no more than four periods per day, and do not vary in start or stop times.

Critical peak pricing (CPP) is a type of dynamic pricing whereby the majority of kWh usage is priced on a TOU basis, but where certain hours on certain days where the system is experiencing high peak demand are subject to higher hourly energy prices that reflect market conditions for peak generation and delivery during peak demand periods. These critical period prices may be known to consumers under conditions such as "day ahead" or "hour ahead" and are typically employed on a limited number of times per year.

Real-time prices (RTP) are energy prices that are set for a specific time period typically on an advance or forward basis and may change periodically according to price changes in the generation spot market.

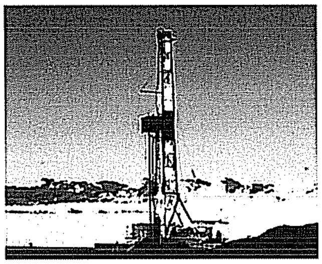
The utilization of any of the aforementioned terms throughout this report represents the use of time differentiated rates.

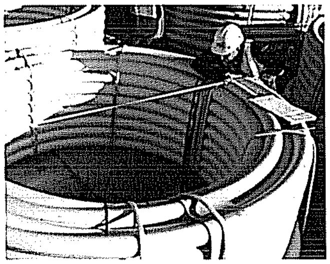
# APPENDIX C: NATURAL GAS IN A SMART ENERGY FUTURE

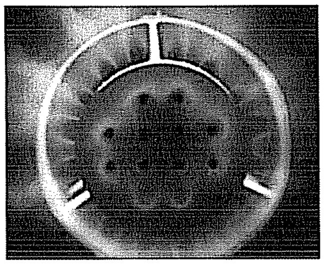
The Energy to Lead

WHITE PAPER

# Natural Gas in a Smart Energy Future







## *A strategic resource for electricity and a smart resource for homes and businesses*

*January 2011*
*GTI-11/0001*

## Legal Notice

This paper was jointly authored by Gas Technology Institute (GTI) and Navigant.

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GTI is a not-for-profit research and development organization. For 70 years, we have been a leader in the development and deployment of technology solutions that contribute to a secure, abundant, and affordable energy future. As such, we provide economic value to the energy industry and its consumers, while supporting government in achieving policy objectives. To date, GTI programs have resulted in nearly 500 products, 750 licenses, and more than 1,200 associated patents.

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*This report's findings are general in nature, and readers are reminded to perform due diligence in applying these findings to their specific needs, as it is not possible for the authors or sponsors to have sufficient understanding of any specific situation to ensure applicability of the findings in all cases. The authors and the sponsors assume no liability for how readers may use, interpret, or apply the information, analysis, templates, and guidance herein.*

## Table of Contents

## Foreword

This white paper is the result of industry-wide support for the development of a compelling vision of a smart energy infrastructure integrating natural gas with electricity from multiple sources, including renewables, resulting in what we describe as a "smart energy future." Our sponsoring organizations recognized the value that abundant, domestic, low-carbon natural gas provides for establishing a secure and affordable energy source compatible with North America's environmental, economic, and societal goals. This white paper promotes the thesis that natural gas' importance to electric smart grid implementation is critical and should be viewed as part of a broader smart energy future. Various energy resources must be utilized to provide reliable, safe, affordable, clean, and efficient energy to North America's homes and businesses.

The development of the vision for *Natural Gas in a Smart Energy Future* included interviews with over 60 individuals and groups representing the entire natural gas industry. Each interviewee was challenged with a set of questions focused on identifying the problems and opportunities, needs and gaps, hurdles and obstacles where action is required now to achieve the vision they could foresee for the industry. To further encourage long range thinking each interviewee was asked to envision the natural gas industry at a point that would be at least 20 years into the future such as 2030 and beyond. Over 470 observations from these interviews were summarized into a vision statement which was then reviewed with a wide variety of industry stakeholders representing federal, provincial, and state regulatory bodies and codes and standards organizations, as well as industry experts and stakeholders.

The vision includes seamless communication and data management between the electric and natural gas infrastructures expanding the concept of a smart electric grid to an energy infrastructure that can enable a smart energy future. This paper also identifies key tools and steps needed in order to achieve the vision in view of policy, regulatory, and technology challenges and proposes a framework to support discussions between natural gas companies, electric companies, regulators, policy makers and other stakeholders.

## Executive Summary

This white paper presents a compelling vision of how natural gas can provide the key to a smart energy future through its efficient, safe, and reliable delivery and use as an abundant, domestic, affordable, low-carbon energy source for all segments of the economy. It also anticipates integrating the natural gas infrastructure with an increasingly "smart" electricity grid and supporting increased levels of renewable energy.

A smart energy future in which natural gas is effectively integrated has the potential to deliver several important advantages:

- Improved safety, energy security, and environmental performance;
- A more efficient infrastructure, with the ability to provide demand response, accommodate emerging technologies, and new sources of supply;
- Improved demand response for electric distribution through switching heating and cooling loads to natural gas and through the use of distributed generation;
- Greater consumer choice resulting in maximum energy value; and
- More optimized energy value from renewable wind and solar through the use of fast ramping dispatchable generation.

Failing to realize a smart energy future in which natural gas is not effectively integrated could create or exacerbate a number of problems:

- The delivery infrastructure will not be at an optimal level for society;
- Higher energy costs for consumers;
- Consumer options for efficient energy use will be limited;
- Greenhouse gas emissions will increase and be more costly to manage;
- The increased use of intermittent renewable energy sources will create performance issues for the electric grid that could have been effectively addressed; and
- Demand response options for the electric distribution system will be limited and more costly.

### *A Smart Energy Future*

The term "smart grid" is widely used to describe a more advanced network of electricity generation, delivery, and end use applications. A smarter energy infrastructure including natural gas would also provide consumers with more timely information for making energy decisions. Action is required now to get to the smart energy future of 2030 and beyond. Available energy sources and infrastructure will need to be optimized to meet North America's overall energy needs in a manner that is:

- Clean and sustainable;
- Reliable and secure;
- Affordable and efficient; and
- Robust and flexible.

A smarter energy future assumes diverse and lower-carbon energy resources are combined with an energy delivery infrastructure that is more reliable and secure than what we have today. This will require technological advances to enhance the efficiency of energy use and reduce greenhouse gas emissions, as well as energy efficiency improvements to reduce consumers' carbon footprint. All of this must be accomplished with a focus on cost in order to maintain the global competitiveness of North America and maintain affordability for energy users.

## The Vision for Natural Gas

Natural gas in North America is a critical energy resource, representing a quarter of the total energy consumed in the United States and Canada. New shale gas discoveries have significantly increased supply estimates for the United States and Canada, as well as globally. North American natural gas is efficiently distributed to and used for home and building heating, water heating, and in industrial processes. Natural gas also is a significant fuel for electric power generation and is the fuel of choice for new electric power plants. The U.S. Department of Energy (DOE) forecasts that 900 of the next 1,000 power plants built will be fueled with natural gas.[1]

Therefore, the vision for natural gas in a smart energy future presented here acknowledges the value of natural gas as a strategic resource for electricity, and a smart resource for homes and businesses. Some of the technology included in the vision does not yet exist or is not fully implemented. With further development however, these technologies could be made available as we progress toward the 2030 vision.

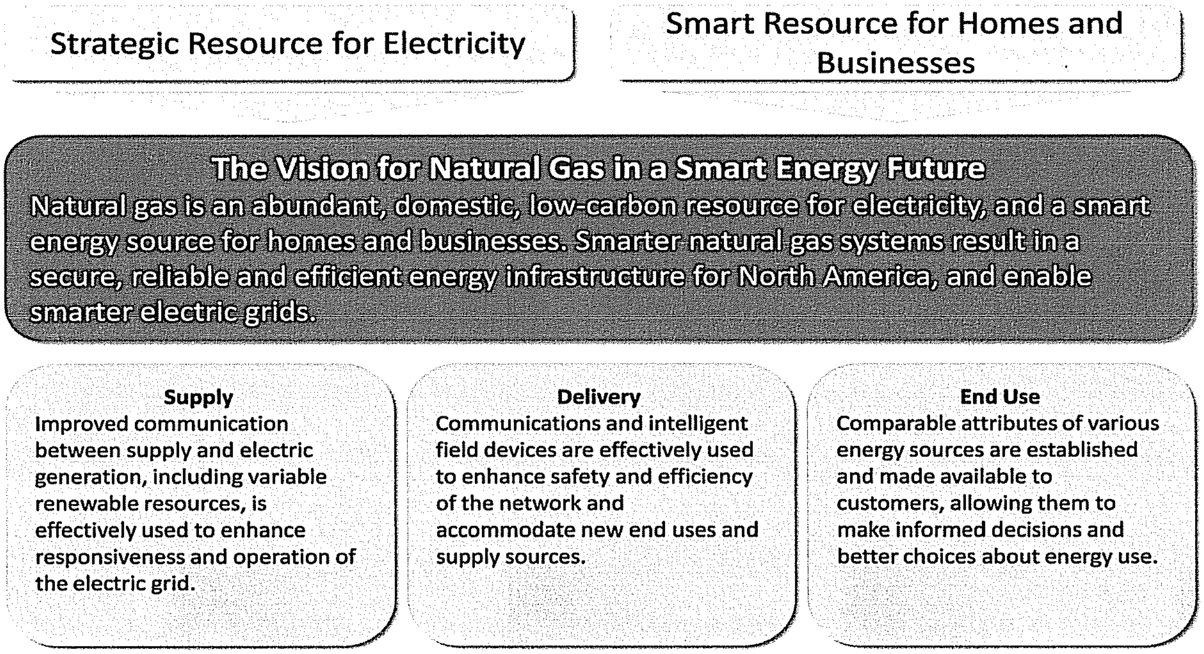
For purposes of simplicity within this white paper, the natural gas industry will be discussed as being represented by three broad sectors.

*Supply:* Exploration and production, natural gas processing, gathering pipelines, compressor stations, and storage.

*Delivery:* Transmission and distribution piping, compressor stations, and storage facilities used to deliver natural gas.

*End Use:* Full economic spectrum of consumers from industrial, power generation, residential, commercial, and other uses including transportation.

The supply, delivery, and end-use sectors each must address key challenges in order to fully realize the vision for natural gas in a smart energy future *(Figure 1).*



Strategic Resource for Electricity

Smart Resource for Homes and Businesses

**The Vision for Natural Gas in a Smart Energy Future**

Natural gas is an abundant, domestic, low-carbon resource for electricity, and a smart energy source for homes and businesses. Smarter natural gas systems result in a secure, reliable and efficient energy infrastructure for North America, and enable smarter electric grids.

**Supply**
Improved communication between supply and electric generation, including variable renewable resources, is effectively used to enhance responsiveness and operation of the electric grid.

**Delivery**
Communications and intelligent field devices are effectively used to enhance safety and efficiency of the network and accommodate new end uses and supply sources.

**End Use**
Comparable attributes of various energy sources are established and made available to customers, allowing them to make informed decisions and better choices about energy use.

*Figure 1. The Vision for Natural Gas in a Smart Energy Future*

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[1] http://www.energy.gov/energysources/naturalgas.htm (Last visited 11/17/2010)

## Achieving the Vision

Pursuing the vision for natural gas in a smart energy future by 2030 must begin now. By enhancing the energy resource mix and infrastructure that is in place, and by fully implementing existing and emerging technologies and business models, achieving the vision is possible in the 2030 timeframe. However, achieving the vision requires action to create or enhance key capabilities within each of the major sectors as follows.

***Supply: Within the Supply sector, establish tighter coordination of natural gas supply and natural gas-fired electricity generation to complement variable renewable resources, thereby enhancing responsiveness and operation of the electric grid.***

Natural gas currently fuels a large portion of the electricity generation portfolio, and this is increasing as compliance with environmental regulations reduces the number of power plants with high greenhouse gas emissions and/or prohibitive regulatory requirements and lead times. Because renewable energy availability varies due to normal daily and even hourly fluctuations in wind and sunlight, fast-acting generators fueled with natural gas can balance power fluctuations. These generators can also regulate grid voltage and frequency, which is necessary to tap the full potential of renewable energy. Tighter coordination and information sharing between electric grid operators and gas suppliers, and technology advancements are key factors to ensure adequate gas supply to generators. Specific capabilities include:

- Automated high ramping supply response;
- Wide area monitoring, visualization, and control;
- Predictive load modeling and forecasting;
- Real time inter-grid communications (gas and electric);
- Automated/dispatchable market area storage; and
- Peak electric demand management assistance.

***Delivery: Within the Delivery sector, create or improve sensing, monitoring and controlling technologies to effectively enhance the safety and efficiency of the network and accommodate new end uses and emerging supply sources.***

The design and construction of the natural gas delivery system of today is typically based on satisfying the requirements of the existing and reasonably foreseeable peak load for a 30-year period. The system of the future will be expected to accommodate emerging technologies and electric demand response programs that have the potential to increase natural gas load. The system also will be expected to accommodate energy efficiency programs that have the potential to decrease peak load. Finally, the system of the future will be expected to accommodate emerging local or regional sources of supply that will differ in quality and composition from those of today. By creating or enhancing the ability to estimate and control load and supply, as well as volume and pressure on a real time basis, the utilization of the infrastructure can be significantly improved. The delivery sector needs improved technologies to provide:

- Detection/prediction of third party damage;
- Automated leak detection and notification;
- Automated flow control and volume/pressure management;
- Automated shut-off;
- Gas quality monitoring and management; and
- Btu composition monitoring at the customer exchange (billing).

Natural gas fueled microgrids comprised of one or more interconnected distributed generation and combined heat and power (DG/CHP) units are one example of an end use that is anticipated to be part of the smart energy future and supported by the natural gas delivery infrastructure. A microgrid incorporates groups of small power and/or combined heat and power generators and loads in systems interconnected to the utility grid, or operated independently as islands. These systems are well suited to applications where there are concentrations of energy consumers needing both electricity and heat, such as industrial facilities, hospital complexes, college campuses, and other facilities with similar construction. Microgrids can help improve the utilization of the energy delivery infrastructure, defer electric generation and delivery upgrades, reduce electric transmission losses, improve energy service reliability, and reduce overall energy costs for consumers within the microgrid. Microgrids will require adequate local natural gas and electricity infrastructures, and the ability to manage energy production and consumption actively and locally.

***End Use: Within the End-Use sector, implement technology to help consumers make well informed energy choices.***

Energy supply is becoming more complex, with new resources such as wind, solar, and biofuels providing a host of new choices for consumers. The problem is consumers do not have a clear picture of where their energy comes from, what it really costs to produce and deliver it, and what impacts it has on the environment and society. Moreover, it is not possible to make consistent comparisons among energy sources. Customers need to have information about the energy they use, better tools to manage their energy use, and access to pricing programs that allow them to value their energy choices properly. Specific capabilities needed include:

- Adoption of full-fuel-cycle analysis in codes, standards and energy labeling;
- Moderating peak electricity demand by using natural gas powered cooling solutions in the commercial applications and natural gas powered DG/CHP systems on an aggregated basis or as part of a microgrid for residential and/or commercial consumers;
- Advocating the use of CHP systems to supply power, heat and cooling at industrial and commercial applications;
- Plain language educational programs for consumers;
- Suite of tools allowing consumers to make smart energy usage choices;
- Consumer energy optimization;
- Hybrid electric/renewable energy/natural gas appliances capable of providing space conditioning, water heating, cooking, and clothes drying; and
- Measurement and verification of energy efficiency program participation.

These capabilities listed above are explained in more detail in the Appendix.

## Benefits

Achieving the vision requires a long term commitment to transforming our energy systems, but we must take action now. Some benefits, like increasing asset utilization and lowering energy costs, will be most noticeable as technologies are deployed fully across the energy infrastructure over many years. Others, like increasing reliability or equipment life, will be more localized, and will yield benefits incrementally.

In the smart energy future, consumers will have a clearer picture of their energy usage and will be able to monitor, manage and conserve energy while protecting the environment. New technology platforms will be provided allowing for the introduction of new products and services. A coordinated network of sensors and control technologies will help consumers utilize energy resources according to individual preferences and value criteria.

The delivery infrastructure also will benefit from additional information from a network of sensors and control technologies to provide transmission and distribution companies with real-time information about customer load, and network volume and pressure. This will enable improved asset utilization, diversification of supply sources, system reliability, service quality, and safety.

### ***Recommendations for Action***

Achieving the vision in the long term will require a number of near term actions related to policy, technology development, and implementation of key capabilities in each of the industry sectors.

#### *FOR POLICYMAKERS:*

#### *Research and Development/Budget*

- Include natural gas in advanced metering infrastructure development to optimize common infrastructure, interoperability and cross-compensation among all utility infrastructures including electricity and water;
- Ensure that future federal funding programs including Smart Grid encourage and allow the use of funding for dedicated natural gas projects and combined electric/natural gas projects;
- Develop a technology roadmap for natural gas in a smart energy future, including critical input from a broad group of stakeholders and the energy technology R&D community;
- Increase governmental funding for basic as well as applied research in natural gas safety and reliability and smart energy infrastructure technology; and
- Establish a governmental public-private research, development and deployment program for natural gas similar in size to the electric Smart Grid programs that includes component and system suppliers.

#### *Regulatory*

- Expand the use of source energy standards to recognize the value of full-fuel-cycle energy efficiency and carbon emission benefits and incorporate full-fuel-cycle analysis in all conservation and energy efficiency standards, including common measures of energy and greenhouse gas emissions;
- Expand ongoing Smart Grid standards development efforts to include natural gas;
- Provide consumers information about energy usage and energy appliance selections so they can make educated decisions.
- Modify the International Green Construction Code to ensure that every new building has access to natural gas service where available;
- Modify market rules to facilitate and create procedures for direct communications between pipeline and electric grid operators to fully optimize the usage of energy.
- Promote real-time communications between the gas and electricity grids;
- Approve projects in a timely manner to ensure natural gas infrastructure can meet the needs of all current and future end-uses; and
- Make energy efficiency programs neutral with respect to energy sources, and encourage collaboration among all energy providers.

## FOR INDUSTRY:

### *Enhance or Create Capabilities for Supply*

- Create and expand real-time communications between the gas and electricity grids;
- Enhance systems to manage natural gas supply for fast-ramping generation to complement variable renewable resources and provide ancillary services; and
- Actively engage federal, provincial, and state regulators to help resolve the issues related to developing shale gas as a long-term energy source.

### *Enhance or Create Capabilities for Delivery*

- Ensure the natural gas infrastructure can meet the needs of all current and future end-uses;
- Enhance the system capability to accept and distribute a wide range of renewable gas sources;
- Ensure current and future natural gas infrastructure can accommodate emerging technologies, peak demand, energy efficiency programs, and new sources of supply; and
- Create or enhance capabilities to improve natural gas asset utilization on a real-time basis.

### *Enhance or Create Capabilities for End Use*

- Develop cost effective systems to be used to moderate peak electricity demand by using natural gas powered cooling solutions in the commercial applications and natural gas powered DG/CHP systems on an aggregated basis or as part of a microgrid for residential and/or commercial consumers;
- Advocate the use of DG/CHP systems to supply power, heat and cooling at industrial and commercial applications;
- Develop hybrid electric/natural gas appliances capable of providing space conditioning, water heating, cooking, and clothes drying; and
- Provide customers the information to make educated choices about their energy usage and energy appliance selections.

## Defining a Smart Energy Future

In recent years, the term "smart" has come to signify capability and quality in numerous products and services. In the energy industry, the term "smart grid" is now widely used to describe a more advanced network of electricity generation, delivery, and end uses. While the smart grid has many different meanings depending on one's point of view, it is generally accepted that a smarter grid is more reliable, operationally efficient, and cost-effective. In addition, a smarter grid can better accommodate renewable energy resources such as wind and solar, and power cleaner vehicles and more efficient appliances.

This paper describes natural gas' role in the actions required now to get to a smart energy future in the timeframe of 2030 and beyond. The smart energy future includes natural gas and electricity optimally coordinated in an energy value chain to power homes and businesses, keep us comfortable, and drive our economy while preserving our environment and national security. The smart energy future includes four characteristics *(Figure 2).*

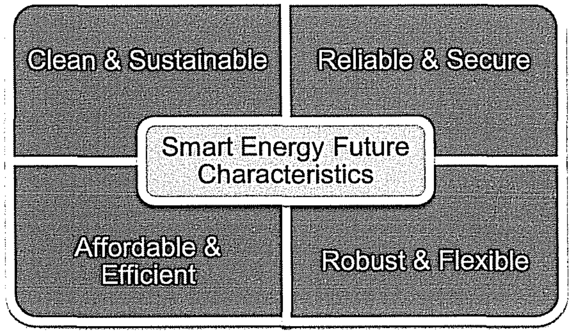

*Figure 2. Characteristics of a Smart Energy Future*

While these characteristics do not exist fully with the energy resource mix and infrastructure currently in place, a full implementation of existing and emerging technologies and business models, will make it possible. Because of its qualities, natural gas can play a critical role in making a smart energy future a reality.

In the smart energy future a diverse and lower carbon energy resource mix will be implemented within a delivery infrastructure that is more reliable and secure than what we have today. This will require an increasing share of renewable energy resources and other technologies to reduce carbon emissions. It also will require improving energy efficiency and reducing the carbon footprint of all energy consumers. Finally, this all must be accomplished while containing the cost of energy by ensuring investments in smart technologies to demonstrate value for energy users.

### *Natural Gas is Clean and Sustainable*

Analysis by Gas Technology Institute (GTI) suggests an increase of natural gas use in electricity production from central generation and distributed generation, transportation, and residential, commercial and industrial applications can be a major component in reaching a 42 percent reduction in U.S. carbon emissions by 2030. Natural gas provides the most direct means for immediate and sustainable carbon dioxide ($CO_2$) reduction because:

- Natural gas-fired power generation emits the least $CO_2$ per BTU of any fossil fuel, with 56 percent lower $CO_2$ emissions than coal, the dominant electricity generation fuel in the United States;
- The direct use of natural gas in applications where heat is required such as for space conditioning or water heating is much less carbon intensive than using electricity for the same application, particularly when the electricity is generated with high-carbon fuels;

- As part of the electric smart grid, natural gas generation can be quickly ramped to complement variable renewable electricity generation such as wind and solar, enabling these carbon-free generation technologies to enter the resource mix;
- The expanded development of renewable gas (biogas) will further reduce the carbon intensity of the energy resource mix in North America; and
- The development and commercial deployment of carbon capture and storage for natural gas power plants will allow gas generation to operate at near zero GHG emissions.

### Natural Gas is Reliable and Secure

The North American natural gas infrastructure is an interconnected system of producing wells, gathering lines, processors, transmission and distribution pipelines, compressor stations, and storage facilities serving over 75 million customers with a history of close to 100 percent reliability. When the reliability of the natural gas delivery system is paired with natural gas-fired electric power generation, the combination results in a proven, conventional technology that is highly dependable compared with other technologies. The integration of natural gas with electricity into a highly reliable energy delivery infrastructure would provide an extraordinary combined level of reliability, especially when coupled with applications interconnected with this integrated grid such as backup electricity generation, microgrids, and loops of heated or chilled water managed as thermal grids.

New shale gas discoveries have significantly increased supply estimates for the United States and Canada, as well as globally. A recently released report on natural gas by Massachusetts Institute of Technology (MIT)[2] summarized resource estimates from a variety of sources and concluded the mean remaining natural gas resource base is around 2,100 (trillion cubic feet) Tcf or about 92 times the annual U.S. consumption of 22.8 Tcf in 2009. With deployment of technologies that can cost-effectively extract natural gas, North America has enough natural gas resources for at least the next 100 years.

### Natural Gas is Affordable and Efficient

Natural gas can be delivered from the wellhead to consumers at 91percent efficiency utilizing the delivery system throughout North America[3]. No other energy delivery system, from source of energy production to end-use, is comparable. Almost all natural gas used in North America originates in North America, and is delivered cost effectively and efficiently through an extensive transmission and distribution system. When the future cost of plant construction, fuel price, and $CO_2$ are considered, natural gas generation has a lower levelized cost of electricity than nuclear or coal-fired generation. Natural gas fired electricity generation also is not subject to a number of environmental issues related to plant-siting and waste associated with other forms of electricity generation. When the source energy attributes noted above, determined through full-fuel-cycle analysis from production to end use, are compared to any other major energy source for consumers a favorable advantage for overall energy efficiency and carbon emissions is shown to be available to consumers as they make their energy choices. Whether those choices are to include natural gas service as part of new construction, which type of energy to use for space conditioning, water heating, cooking, or clothes drying or when they are deciding which appliance to purchasing as a replacement natural gas provides an efficient cost effective energy source.

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*2 "The Future of Natural Gas, an Interdisciplinary MIT Study, Interim Report," MIT Energy Initiative, Massachusetts Institute of Technology, 2010.*

*3 American Gas Association, "Source Energy and Emission Factors for Residential Energy Consumption," August 2000*

### *Natural Gas is Robust and Flexible*

In 2009, approximately 22.8 Tcf[4] and 2.6 Tcf[5] of natural gas was delivered to U.S. and Canadian consumers, respectively, through an intricate infrastructure including gathering systems, processing facilities, market centers, compressor stations, and pipelines. Along the way there are options to store natural gas in underground facilities and to transfer natural gas between pipeline systems. Added flexibility is provided by infrastructure to import or export natural gas.

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[4] *http://www.eia.doe.gov/energyexplained/index.cfm?page=natural_gas_home#tab2 (Last visited 11/17/2010)*

[5] *http://www.cga.ca/publications/documents/Chart7-SalesandExports.pdf (Last visited 11/17/2010)*

## The Vision for Natural Gas

### The Source of the Vision

The vision for *"Natural Gas in a Smart Energy Future"* is the product of extensive discussions among leaders from across the natural gas industry. During a series of interviews, workshops, and forums, these experts were challenged to think about the natural gas industry in 2030 and beyond. They talked about opportunities to improve our energy infrastructure, and achieve the four *(Figure 2)* characteristics of the smart energy future.

This vision expresses a consensus of the industry participants; some of the technology included in the vision does not exist or is not fully implemented today, but the industry participants believe it is important to start now to achieve this vision. With development and application, these technologies could be made available within the 2030 timeframe.

### The Vision

In North America natural gas is a critical energy resource, representing a quarter of the total energy consumed in the U.S. and Canada. Consumption is well distributed among industrial processes, power generation, commercial, residential, and other uses including transportation *(Figure 3).*

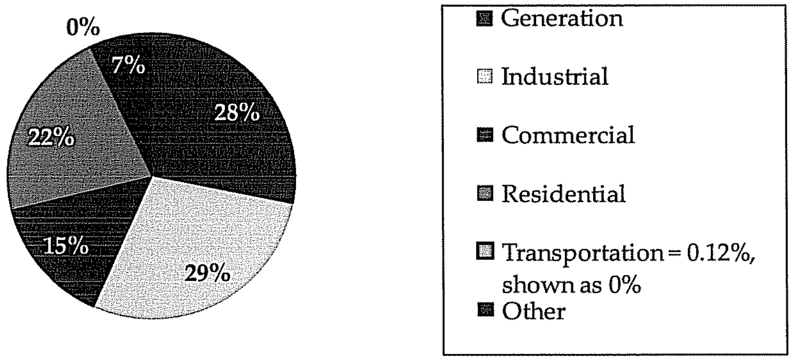
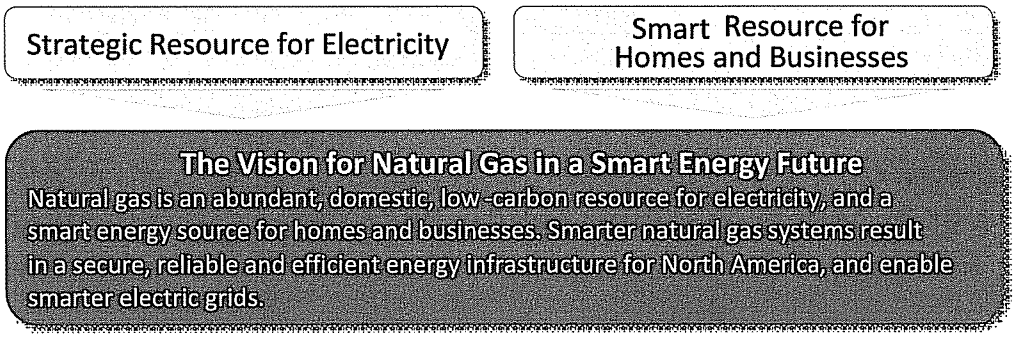


*Figure 3. Breakdown of North American Natural Gas Consumption by Sector in 2009*

Therefore, the vision for natural gas in a smart energy future *(Figure 4)* acknowledges the value of natural gas as a strategic resource for electricity production in central power plants and distributed generation. It also is a smart resource for homes, businesses, and as a fuel for medium and heavy duty vehicles. The supply, delivery, and end-use sectors are three major sectors involved in achieving the vision for natural gas in a smart energy future.



**The Vision for Natural Gas in a Smart Energy Future**

Natural gas is an abundant, domestic, low-carbon resource for electricity, and a smart energy source for homes and businesses. Smarter natural gas systems result in a secure, reliable and efficient energy infrastructure for North America, and enable smarter electric grids.

*Figure 4. Vision for Natural Gas*

## The Vision for Supply

The responsiveness and operation of the electric grid is improved through increased levels of direct and timely communication among wholesale gas producers and marketers, transporters and electric generators, including communications from variable renewable resources.

- *Direct communication* allows natural gas suppliers to respond to fluctuations in electricity production more quickly and efficiently.
- *Fast-ramping gas-fired power generation* complements variable renewable resources to provide reliable and secure electricity.
- *Demand forecasts* for electricity are available to gas suppliers, helping ensure fuel is available when and where it is needed. Energy market information is available, allowing tighter coordination between pipeline and grid operators.
- *Real-time information* about weather, demand, infrastructure, and operating conditions is shared among all parties.

## The Vision for Delivery

Delivery effectively uses two-way communications and intelligent field devices to enhance safety and efficiency of the network and effectively serve new end uses and supply sources.

- *Robust and flexible infrastructure* responds to consumer needs and enables pipelines and local distribution companies (LDCs) to safely and efficiently increase capacity and actively manage volume and pressure using a network of sensors, two-way communications, and automation. This infrastructure readily accommodates diverse sources of supply.
- *Optimized investment* is possible as better load forecasts, network monitoring and demand management techniques are employed to improve asset utilization, capital deployment, and increase useful life.
- *Emerging technologies* such as microgrids, thermal grids that manage loops of heated or chilled water, and alternatively-fueled vehicles create new uses for natural gas and electricity.

### Natural Gas – Now and in the Future

Natural gas is not simply fuel consisting of methane, nor is it homogenous in chemical and physical makeup. The specific properties and compositions of natural gas are complex and a function of many factors, including: 1) resource supply characteristics, 2) level of gas processing, and 3) degree of comingling prior to and during transportation.

Conventional gas basins were the original source of most natural gas in North America because the gas was easily accessible and extracted. Unconventional gas sources historically were more difficult to induce production of gas until recent technological breakthroughs in drilling and hydro-fracturing made it economically favorable. Unconventional sources include: (1) Shale gas (natural gas sourced from the original shale formations that has not permeated into another geologic formation); (2) Tight sand gas (formed where gas migrates from the source rock into a sandstone or carbonate formation); and (3) Coal bed methane (generated during the transformation of organic material to coal).

Another source of gas included in the grouping of gas referred to as unconventional, that is increasingly being introduced to the natural gas delivery systems, is known as renewable gas or biogas.

Local gas distribution and transmission companies are progressively seeking to purchase and take delivery of fuel gas derived from a multitude of new sources. There is a need within the industry for information to compare these new sources with traditional natural gas supplies.

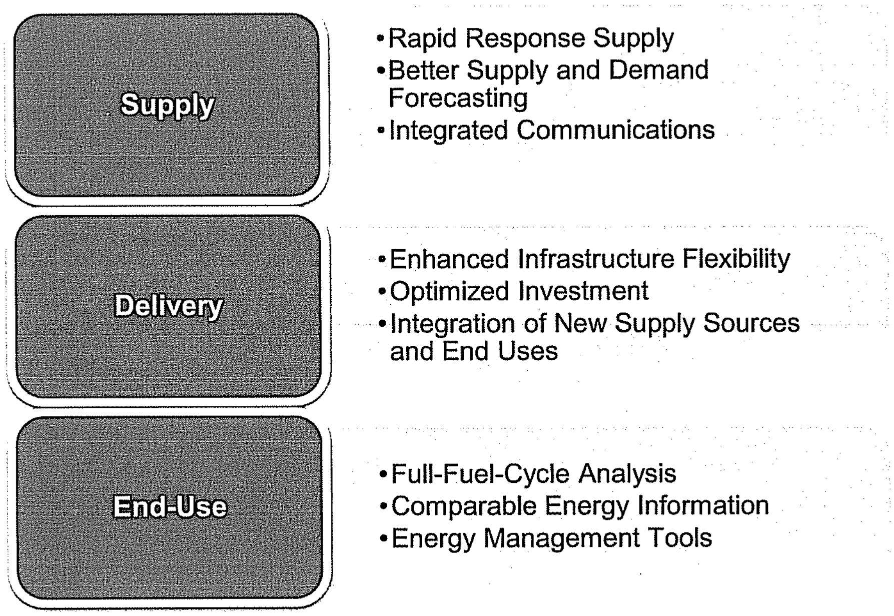
## The Vision for End-Use

Comparable attributes of various energy sources have been established and made available to consumers, allowing them to make informed decisions about energy use.

- *Transparent, repeatable analyses* are done for multiple energy sources to directly compare attributes such as energy content, price, and environmental quality on a full-fuel-cycle basis.
- *Comparable energy attribute information* is available to consumers in a simple and convenient form.
- *Energy management tools* provide timely intelligence aiding consumers in making energy choices.

## Achieving the Vision

For many years the natural gas infrastructure has met the needs of the consumer. However, it must evolve further to support the level of operations necessary to achieve the vision and associated benefits of a smart energy future. *Figure 5* summarizes where work is required in order to fully capture the benefits of natural gas in a smart energy future. These challenges cannot be met today with the energy resource mix and infrastructure that is in place; however, by fully implementing existing and emerging technologies and business models, it is possible. Because of its qualities, natural gas can play a foundational role in achieving each of these objectives, and making the smart energy future a reality. The following sections describe in more detail the steps to achieve the vision for 2030, and present some key capabilities/functions/technologies. These capabilities are highlighted based on GTI/Navigant's review of the information collected from extensive interviews and dialogue with industry experts and stakeholders as well as their own in-depth understanding of the natural gas industry.



**Supply**

- Rapid Response Supply
- Better Supply and Demand Forecasting
- Integrated Communications

**Delivery**

- Enhanced Infrastructure Flexibility
- Optimized Investment
- Integration of New Supply Sources and End Uses

**End-Use**

- Full-Fuel-Cycle Analysis
- Comparable Energy Information
- Energy Management Tools

*Figure 5. Key challenges by sector*

### *Capabilities for Supply*

The demand for natural gas can change dramatically. Weather significantly affects heating load for direct use, and can also affect the electricity demand served by natural gas generators specifically as variable renewable resources play an increasing role in the energy supply mix. Wind and solar generation are variable by nature, and in some instances grid operators and electric system planners have struggled to maintain grid reliability as a result. In the past, the availability of natural gas for generation may have been taken for granted. However, as more variable resources are utilized, more fast-ramping generation will be required to balance them. Where gas generation is used for this purpose, pipeline pressure and volume must be actively managed through tighter communications and information sharing to respond to variable electricity production in conjunction with storage facilities and pipeline service offerings.

Unfortunately, the time horizons for planning and operating the electric and gas grids differ due to physics and markets. Tighter integration of gas and electricity in a smart energy future means the alignment of demand forecasts must improve to ensure supply is made available to meet demand. This will also require better information sharing between pipeline operators and electricity grid operators.

When actual conditions deviate from forecasts, pipeline operators and electricity grid operators must still maintain system reliability. An electric grid operator may call on a generator with little notice, and it must be ready to deliver. This requires a ready fuel supply, and the pipeline operator must have requested and delivered it – before the generator was called upon. A more fully integrated smart energy grid requires direct communication between suppliers, pipeline operators and electricity grid operators. This may require modifications to market rules.

To achieve the vision for supply, a wide variety of capabilities will need to be developed or enhanced. Several are highlighted below.

*Real Time Inter-grid Communications (Gas/Electric)* will need to be provided, including two-way, secure, redundant path communications between pipeline operators and generators. Redundant paths allow the signals to travel via either wireless or wired paths, perhaps using radio, satellite, cable, power-line, or telephone to ensure two-way communication is maintained. This approach leverages the high speed communications linkage connecting the central office with each individual sensor, controller or any other information gathering point within the gas/electric infrastructure, commonly referred to in the communications industry as backhaul. An approach of this type would provide real-time data which can be acted upon by automated intelligence systems and/or system operators, resulting in coordinated operations between the electric and gas grids.

*Wide Area Monitoring, Visualization, and Control* includes the use of two-way communication technologies to collect, analyze, and interpret data from sensors and monitoring locations along the transmission pipelines. The data collected would be analyzed by system operators with the help of computer programs to provide beneficial information allowing the real-time status of the system to be visualized and controlled. A system with these capabilities will provide proactive response for predicted events and real-time reactive responses for any unforeseen events.

## Coordinated Operation of Natural Gas and Electricity Infrastructures

Today the natural gas and electricity infrastructures are largely controlled independently, with little cross-communications which is primarily the result of sizable differences in time constants and system dynamics. Electric loads have major daily and seasonal fluctuations but smaller annual fluctuations, whereas natural gas loads have smaller daily variations but major annual fluctuations. Gas storage can exceed 20% of the annual consumption, with the storage capability varying significantly by region. Due to the system dynamics it is often assumed the gas system will be able to instantly respond to demands from the electric system, however, both theoretical as well as real-life experiences have shown these assumptions are false. A new model could be developed to accurately anticipate the impacts of substituting high ramp rate gas generation for other resources such as intermittent wind resources over broad geographic areas. The targeted use of the model could improve long range planning, contingency analysis, and risk mitigation for the two energy grids.

Joint modeling could account for dependencies including weather, changes in supply and demand, and emergencies, and account for the differences in operational time constants between the infrastructures.

Developing an integrated operational capability would involve:

- Piloting an operational model in a single region or control area;
- Extending operations to multiple control areas in a wide-area demonstration; and
- Finalizing a national-scale operational framework.

Technology capable of providing *Automated High Ramping Supply Response* results in delivering natural gas at the pressures and volumes required to operate fast-ramping generation facilities efficiently. This would work by connecting electric and natural gas transmission through an infrastructure equipped with sensing and controlling technology to allow real-time response.

Novel methods for *Automated/Dispatchable Bulk Market Area Storage* need to be developed for every market area to provide large volume storage available for immediate response to support the continued operations of the natural gas system. Storage of this type needs to be automatic and flexible with response rates comparable to those provided by today's salt dome storage facilities which are geologically restricted to certain regions of North America.

*Predictive Load Modeling and Forecasting* needs to be developed allowing the use of current consumer load data in combination with historical load data, current and historic weather data and current and historic major consumer use patterns. The resulting modeling and forecasting software would provide trend analysis to allow accurate load prediction and forecasting.

*Peak Electric Demand Management Assistance* includes the direct communications to the natural gas grid through the use of technologies to monitor and proactively provide appropriate peak electric load reduction and/or demand response in support of the needs of the electric infrastructure.

## Capabilities for Delivery

Emerging technologies such as microgrids, thermal grids, hybrid appliances, and alternatively fueled vehicles will create new uses for natural gas and electricity. To respond to consumer needs, LDCs must be able to ensure the infrastructure is capable of accommodating these new end uses while continuing to ensure the integrity and safe operation of their gas systems.

For many years, natural gas distribution systems and electric distribution systems have been planned and built separately to meet the forecast peak demands of each infrastructure typically based on a 30-year planning horizon. A smart energy future includes implementing ways to be more efficient. Better demand information, new end-use technologies and demand management strategies can be employed to flatten demand curves and reduce infrastructure cost.

New end use technologies may also require enhanced delivery capability. Many of these technologies require further demonstration, and utilities working with developers will ensure the necessary accommodations are made so the full value of the new technologies can be realized. The gas distribution system will also be expected to deliver gas from new supply sources being developed.

### Enabling New Energy Technologies

The full scale demonstration of technologies can be key to their commercialization. Regional demonstrations of a microgrid (a localized grouping of power and/or combined heat and power generation, energy storage, and loads that normally operate connected to a traditional grid that are coupled and connected through a single point or disconnected and function autonomously) should be considered addressing the wide variety of possible applications. For example, there are areas in North America where economic development is an imperative. The use of a microgrid to provide premium power could be offered to attract manufacturing and high tech industries. With the pressure being placed on older coal generating power plant to meet emissions limitations, it may be appropriate to evaluate the long standing strategy of a single large central generating facility versus smaller combined cycle natural gas generating stations located throughout the same area being served. These smaller natural gas units would be interdependent and have sufficient redundancy to back each other up should an unplanned outage occur at any one location. This configuration would also have the ability to seamlessly incorporate intermittent renewable power. Using a microgrid for communities that are susceptible to outages, an approach known as "islanding" may be another attractive use of this technology. Islanding may be an effective tool as part of a peak demand response where the natural gas unit is used as a backup to the electric grid or it may be preferred to use the natural gas unit as the prime source of power and the electric grid as the backup. One final example of the use of microgrid is to optimize the performance of renewable technology. Renewable resources are often criticized due to their intermittency and low capacity factors. Combined installations that directly link renewable energy with natural gas generation and possibly energy storage may be key in moving both technologies forward.

Similar to the approach we used for supply, we have identified a wide variety of capabilities and functions that must be developed or enhanced in order to achieve the vision for delivery. We have highlighted a few that would be among those needing to be created or enhanced.

*Automated Flow Control and Volume/Pressure Management* includes the development of sensing technology capable of monitoring and reporting volume and pressure that can be acted upon by artificial intelligence systems or system operators. The function of automated flow control and volume/pressure management would use communications technologies coupled with monitoring and control technologies. This approach uses real-time information on volume, pressure and quality to maintain system operations. This broad area of functionality could also include smart gas metering and load monitoring devices at the consumer location that allow the LDC to monitor and manage the system to ensure the consumer load requirements are met safely and reliably. This may include real-time metering, remote disconnection, outage detection, and other features.

*Automated Shut-off* includes the development and use of a combination of sensors and communications technologies located strategically throughout the gas network capable of detecting and reporting incidents. This warrants activating one or more control devices and providing the data on a real-time basis to be acted upon by an artificial intelligence system and/or a system operator. The automated shut off could be implemented in transmission pipelines, local distribution lines, or at the meter.

*Detection/Prediction of Third Party Damage* would utilize a combination of visual and/or proximity sensing based artificial intelligence to notify operations staff of a potential incident that could result in damage or of an occurrence of recent damage.

*Automated Leak Detection and Notification* would include the development of sensors and communications for real-time monitoring and reporting of methane/ethane levels. A detection and notification system would also include a system capable of verifying consumer contacts and allowing operators to determine if action is required.

Advanced sensors and communications could enable *Gas Quality Monitoring and Management*, and provide gas system operators the ability to obtain Btu, compositional, and trace constituent information from the gas throughout the transmission and distribution system. Similarly, *Btu Composition Monitoring at the Customer Exchange (Billing)* would measure calorific data coupled with volume and pressure sensing to ensure the supplier and consumer that contract obligations are met. All of this support would allow system-wide quality management, and facilitate the seamless integration of supplies including shale gas and renewable gas (biogas).

## Capabilities for End-Use

The supply of energy is becoming more complex. New energy resources such as wind, solar, and biofuels will provide a host of new choices for consumers. The problem is most consumers do not have a clear picture of where the energy comes from, what it really costs, and what impacts it has on the environment and society. Consumers need to have information about the energy they use, better tools to manage their energy use, and access to pricing programs that allow them to value their energy choices properly. Factual, repeatable analyses of the full-fuel-cycle efficiency and cost of multiple fuels must be conducted and directly compared so consumers can make energy choices that best meet their needs. This should include accounting for regional variations in fuel mix and availability.

*Full-Fuel-Cycle Analysis in Codes, Standards and Energy Labeling* should be adopted for buildings and appliances to include source energy or what is referred to as full-fuel-cycle analysis as the basis for energy efficiency and emissions standards. A requirement should also be established for the consumer to have access to available natural gas wherever natural gas distribution occurs.

### Codes and Standards for Buildings and Appliances

One way to directly and quickly influence the energy choices being made is to ensure the codes and standards for buildings and appliances are up-to-date. Quick examples to be addressed are the use of Full-Fuel-Cycle Analysis in the building codes and the standards across North America and updating home energy rating systems such as HERS and the Energuide Rating System. Full-Fuel-Cycle analysis is also referred to as source energy and should not be confused with site energy. Source energy is the comprehensive measurement of the amount of energy consumed at the site, plus the energy that is consumed during the extraction, transportation, processing, and distribution of the energy to the point of use. This is in contrast to site energy that is simply the amount of energy consumed at the point of use. Home energy rating system guidelines establish a systematic process for the delivery of whole-house home energy ratings. The ratings also provide evaluation of the cost-effectiveness of options to achieve greater energy efficiency in those homes.

Information about the source, composition, quality, and price of various energy sources must be made available to consumers in an easy to understand and compare format. These attributes should incorporate more comprehensive information, and account for regional differences in resource availability and market options.

Armed with consistent and comparable energy information, consumers should be provided a *Suite of Tools Allowing Consumers to Make Smart Energy Choices* about their energy supply and how they ought to use it. Such tools help consumers distinguish between important factors such as carbon intensity, reliability, price, and other factors.

*Consumer Energy Optimization* can be provided through the development and use of a simple, easy to use, and convenient in-home display and/or a smart thermostat connected with every major energy-consuming appliance. The in-home display and/or smart thermostat would also be capable of two-way communications with utilities to receive demand response requests or time-of-use information. This simple yet sophisticated approach coupled with consumer education will provide the consumer with plain language, site-specific choices for energy use and carbon footprint. The full-fuel-cycle efficiency of end use appliances could be provided to consumers for their end use decisions and full-fuel-cycle could be used by regulators when producing energy efficiency and air emission/carbon regulations.

*Plain Language Education Programs for Consumers* coupled with straight-forward easily understood messaging will allow each consumer to make the energy choices that are right for their situation. Whether those choices are to include natural gas service as part of new construction or which type of energy to use for space conditioning, water heating, cooking, or clothes drying or when they are deciding which appliance to purchasing as a replacement, clear and concise information on energy cost and emissions based on factual, repeatable analysis is essential for a smart energy future.

*Measurement and Verification of Energy Efficiency* is an important function that needs to be fully developed and simplified. It would use sensing and communicating technology to provide a method for determining the energy efficiency impacts of actions taken by the consumer. Improved sensing and communications technologies can also be coupled with sub-metering options for residential, commercial, and industrial consumers to cost effectively monitor individual appliances and equipment.

## Benefits of a Smarter Gas Infrastructure

By beginning now, the capabilities and technologies described in the preceding section will have a significant positive impact for consumers and our economy and will significantly improve the configuration and operation of the energy infrastructure in North America from now to the year 2030 and beyond.

Consumers will have a clearer picture of their energy usage and will be able to monitor, manage, and conserve energy while protecting the environment. New technology platforms will be provided allowing for the introduction of new products and services. Benefits from a coordinated network of sensors and controlling technologies will also be realized for each of the direct use options such as space conditioning, water heating, and cooking. This network of sensors and controlling technologies will recognize the energy needs of the consumer and coordinate these needs with the available information on price and carbon content of the energy options available. With such real-time information, consumers will have simple, easy to understand information to make a smart energy choice.

The increased level of performance of the infrastructure will yield benefits to energy consumers and society in five fundamental categories:

- *Safety* – reductions in injuries, loss of life, and property damage
- *Economic* – reduced costs, or increased production at the same cost, resulting from improved utility efficiency and asset utilization, and better-informed and empowered consumers
- *Reliability and Service Quality* – reduction in interruptions and service quality events
- *Environmental* – reduced impacts of climate change and effects on human health and ecosystems
- *Energy Security* – improved energy security (i.e., dependence on foreign sources)

### *Safety Benefits*

A smarter gas infrastructure will be equipped with sensors, communications, information processors, and control devices to detect and respond to conditions compromising the safety of utility workers and the public. In addition to reducing incidents directly related to the gas infrastructure, automation and remote control can also reduce the need for service workers to perform manual operations in the field. This reduces the chance of traffic incidents and work-related hazards.

Safety related technologies to be created or enhanced include those to reduce or eliminate damage, improve leak detection and location, and detect unauthorized access or changes in condition that may require immediate response. The development and use of advanced global positioning and geographic information systems in conjunction with mobile and/or hand-held devices is another safety related area of technology advancement that complements all aspects of field construction, operations and maintenance.

### *Economic Benefits*

#### *Improved Asset Utilization*

Transmission and distribution pipelines make up a significant proportion of the natural gas infrastructure; the usage of these assets to their full capacity is among the top priorities of the industry. Pipeline capacity is the ability to move natural gas from the point of supply to the point of use and is based on a combination of pipe size and operating pressure. Whether a pipeline system achieves optimal performance is affected by the utilization rate, (which may be influenced by scheduled or unscheduled maintenance), changing market demands, or weather related events impacting operations. A system peak-day usage rate generally reflects peak system deliveries relative to estimated system capacity. Capacity can be influenced by secondary compression and/or line packing or storage.

Technology areas potentially influencing the ability to improve capacity usage include predictive maintenance, improved weather forecasting, and more accurate advanced warning from major consumers of increased load requirements (such as improved communications with electric generators) and real-time stress measurement sensors (versus predictive calculations) for use during line-packing and improved communications with local/regional storage.

Better forecasting and monitoring of load and grid performance will enable grid operators to dispatch a more efficient mix of generation that could be optimized for societal needs while reducing cost. This will include ensuring the base load units are operating at their peak efficiency, renewable resources are fully utilized, and units designed to provide rapid ramping, ancillary services, and system support are coordinated in a manner to address system variability, with the entire operation occurring at the lowest cost.

### *Gas Transmission and Distribution Capital Savings*

The construction of new infrastructure requires a tremendous amount of time and expense to work through the design, engineering, and permitting. The need for new construction may be driven by projections of new load from new construction or from projections that the load for existing consumers will increase. Connecting new consumers, specifically residential consumers, can be a major expense to be cost-justified before it occurs.

Having an improved understanding of peak requirements and real-time load information will enable the designs for new transmission and distribution systems to be optimized for societal needs and capable of accommodating system peaks without being over-built.

**Potential Benefits of Gas Theft Reduction**

Over the last three years, one mid-sized utility has investigated between three and five thousand gas theft incidents annually; one notable case involved $1.4M in stolen natural gas. Assume the average case takes one employee one day to investigate and document and decide if further action is required and that only 10% of the investigations result in prosecutions with each taking one week of a lawyer's time, Using this utility as an example, the following typical cost is calculated - 4,000 cases/year X 8 hours/ investigation X $30/hour = $960,000 to investigate. 400 cases/year to prosecute X 40 hours/case X $50/hour = $800,000 to prosecute. This results in a total cost per year for 4,000 theft cases of $1,760,000 or $440/case. Assuming the value of each theft averages $10,000, 400 thefts per year results in $4 million in value each year for a utility of this size. For every 10% reduction in case load and theft the savings equates to $400,000 in gas that is not stolen and $176,000 in reduced investigation and prosecution costs. The result is an annual savings of $576,000 for every 400 cases eliminated by the use of a smart system.

Extrapolating this result: There were 70,761,000 users of natural gas across the U.S. per AGA in 2008, for an average number of thefts per year of 127,370. Following the logic and the assumptions of cost shown above this number of thefts would result in an investigative cost of $30.6M, legal costs to prosecute of $254.7M and an estimated value of the stolen gas of $127.4M for a total industry estimated cost of $412.7M per year.

*http://articles.chicagotribune.com/2010-07-28/news/ct-x-n-nicor-gas-theft-20100728_1_nicor-gas-natural-gas-nicor-spokesman-richard-caragol*

Optimizing the use of existing assets and deferring capital investments through the use of real-time pressure and volume sensors coupled with real-time load data is another benefit resulting from an integrated communications system. As consumers are provided with educational programs and tools and techniques to make smarter decisions about their energy use, it is reasonable to assume changes will occur in daily, seasonal, and annual load. Energy efficiency programs result in improved end use technology, increased consumer awareness, and/or the ability to provide energy when it is needed either through direct use, load shifting or energy storage on a regional basis are all possible outcomes of a smart energy future.

### *Operations and Maintenance Cost Savings*

Operating and maintaining the extensive natural gas transmission and distribution network costs nearly a billion dollars per year. Implementing intelligence and automation in natural gas systems could yield significant cost savings in operations and maintenance. *Table 1* provides a summary of typical operating and maintenance activities as quantified in an industry report from 2000 for natural gas distribution companies across the United States. Every one percent improvement in operational efficiency contributes over $5 million per year savings in 2010 dollars.

*Table 1. Estimated Annual Gas Distribution Operations and Maintenance Cost*[6]

| Activity | Annual Cost (2010 $MM) |
|---|---|
| **Distribution Maintenance** | |
| Plastic Pipe Locating | 106 |
| Plastic Pipe Main Repair | 46 |
| Plastic Pipe Service Repair | 64 |
| Cast Iron Joint Repair | 9 |
| **Distribution Operations** | |
| Leak Pinpointing | 93 |
| Logging Pressure Readings | 147 |
| Re-lighting | 4 |
| Meter Reading | 58 |
| **Total** | **527** |

### *Theft Reduction*

Gas theft results when the meter is circumvented allowing unauthorized access to the natural gas delivery system with no record of the use. Alternative piping and/or valving are typical methods of meter tampering that have occurred resulting in a low level of usage or no record of usage. In addition to the improvements in public safety resulting from reducing unauthorized access, there are also potential economic benefits associated with reducing gas theft as described in the adjacent call out box.

### *Energy Efficiency and Cost Savings to Consumers*

To optimize the use of natural gas, electricity and other energy resources, accurate and comparable information must be available to consumers. This information must enable direct and fair comparisons of cost, reliability, carbon content, and other attributes of importance to the consumers. Improving sensing and communications technologies coupled with sub-metering options for residential, commercial, and industrial consumers can provide tremendous insight on how individual appliances and equipment can be managed cost effectively. Armed with this information, consumers will be able to make choices about their energy usage and reduce their energy cost.

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*[6] Sources: Nicholas Biederman, Gas Technology Institute, September 2002, GRI-02/0183, and GTI analysis. Assuming a 2.5% annual escalation rate from 2000 to 2010.*

A GTI study[7], completed in 2009, focused specifically on these two issues by analyzing the benefits of increased direct use of natural gas achieved through a cost-effective mechanism to increase the full-fuel-cycle efficiency and reduce greenhouse gas emissions. The GTI study found subsidies provided to increase the direct use of natural gas will provide greater benefits than comparable subsidies to electric end-use technologies with respect to reducing primary energy consumption, consumer energy costs and $CO_2$ emissions.

The study also identified the following benefits could be achieved by 2030, if consumer education and research and development were combined with subsidies to encourage direct use of natural gas:

- 1.9 Quads/2.9 Exajoules energy savings per year
- 96 million metric tons $CO_2$ emission reduction per year
- U.S. $213 billion cumulative consumer savings
- 200,000 GWh electricity savings per year
- 50 GW cumulative power generation capacity additions avoided, with avoided capital expenditures of $110 billion at $2,200/kW.

The summary of energy savings for both natural gas and electricity, financial savings for consumers, and the emissions reductions shown above is a compelling reason to increase the direct use of natural gas through education of consumers and increased funding of research and development activities. Moreover, by providing natural gas at the pressures and volumes required for fast-ramping, natural gas generation facilities equipped with sensing and controlling technology can be efficiently operated providing real-time response. The enhancement of these same functions would allow one or more distributed generation or combined heat and power (CHP) facilities equipped with sensing and controlling technology to provide real-time response during peak demand periods, outage events or as needed for system support. Finally, the same system coordinating the needs of the electric and gas distribution system could readily use distributed generation units to balance the energy needs to support electric vehicle deployment. This use of natural gas technologies would avoid the need for large scale electric distribution infrastructure upgrades as well as a wide variety of other alternate vehicle transportation interests such as those from fleet, municipal, and marine vehicles.

### *Job Creation and Economic Impact*

A study completed in 2009[8], prepared by IHS Global Insight for America's Natural Gas Alliance (ANGA), used U.S. Bureau of Labor Statistics data to estimate the number of workers involved in the production and transportation of natural gas. This in-depth economic analysis concluded in 2008, approximately 622,000 jobs were directly related to natural gas in the United States and the natural gas industry was responsible for supporting an additional 2.2 million jobs. The ANGA study also defined the jobs supported by natural gas including:

- Upstream exploration and production companies
- Midstream processing and pipeline transportation companies
- Downstream LDCs
- Suppliers and onsite construction service providers
- Natural gas pipeline construction
- Manufacturers of field machinery and equipment

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[7] *Neil Leslie, P.E., Validation of Direct Natural Gas Use to Reduce $CO_2$ Emissions, June 26, 2009, Gas Technology Institute.*

[8] *America's Natural Gas Alliance, The Contributions of the Natural Gas Industry to the U.S. National and State Economies, September 2009.*

Job creation and overall economic improvement will result from the significant capital investment in the wide variety of sensing, communicating, data managing, and controlling technologies needed to achieve a smart energy future. Electric utility capital investment in generation, transmission, and distribution in the U.S. over the next 20 years has been estimated to be between $1.5 to $2 trillion dollars[9]. Included in those estimates for electric system upgrades are those associated with smart grid infrastructure which has been estimated to cost a minimum of $165 billion[10] by 2030. It is reasonable to assume the corresponding investments for the natural gas industry would be proportionately scaled. Much of this investment will depend on the technology development enabling each of the capabilities and functions identified here and others to be enhanced or created. Job types will include those in research and development, design and engineering, construction and installation, operations and maintenance, and marketing and sales, as well as all the associated supporting roles.

The ability to fuel a wide variety of direct uses as described above in the section on energy efficiency and cost savings is another beneficial economic outcome of the enhancement or creation of selected capabilities.

### *Reliability and Service Quality Benefits*

While unusual, a gas service interruption can occur in two ways: 1) the consumer discontinues gas consumption to comply with a specific order by the LDC or pipeline company or 2) the loss of pressure and/or volume from the delivery system results in insufficient natural gas to maintain safe and reliable operations and causes an outage for one or more consumers on a local or regional basis.

In both cases, there is an impact to the consumer. There may be an impact to the utility depending on the cause of the interruption and the time and complexity involved in restoring service. Therefore, improving service reliability can provide a significant benefit to consumers and utilities, and in the case of large-scale service interruptions, there may also be a benefit to society. The benefit to consumers is typically determined by the value of service, which can vary by consumer class and geography. Commercial and industrial consumers typically place a higher value on service due to the impact an interruption can have on business operations. The benefit to utilities will depend on the cost of restoring service, including capital equipment replacement and service operations.

Modeling, forecasting, and market area storage could help gas companies provide more consistent supply for consumers as conditions change. This can be particularly important for the supply sector to ensure the supply of natural gas matches the demand. A variety of economic and reliability benefits can result if this can be done in a more precise and real-time fashion.

Tighter integration of natural gas with electricity could also have an important effect on the reliability of electricity service to consumers. By implementing gas-fueled distributed generation, either in stand-alone configurations or in microgrids, electricity outages could be dramatically reduced.

Another area in which natural gas can increase the reliability of energy supply is in connection with variable resources. The increase in variable renewable resources such as wind and solar will alter traditional dispatch practices and operation of the electric grid. In order to maintain reliability, grid operators will come to rely on flexible and efficient resources to complement variable renewable resources. Fast ramping generators could provide capacity, energy, and ancillary services at competitive costs.

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[9] *http://www.infrastructurereportcard.org/fact-sheet/energy (Last visited 11/17/2010)*

[10] *Electric Power Research Institute, Palo Alto, California, Power Delivery System of the Future, A Preliminary Estimate of Costs and Benefits, 1011001, July 2004.*

## *Environmental Benefits*

$CO_2$ emissions result from burning carbon based fuels. Reducing the use of carbon-based fuels or increasing their efficiency through improved appliances or more direct use by the consumer leads to reduced $CO_2$ emissions. The greatest opportunities for natural gas to contribute to carbon-reduction benefits are in power generation and expanded direct use. The largest carbon reductions per unit of natural gas consumed are from CHP systems and direct gas use assuming these uses will be in lieu of electricity consumption by end users.

In 2010 the MIT published an interim report on "The Future of Natural Gas."[11] The report summarized the environmental benefits of natural gas well by stating that:

> *"In a carbon-constrained world, a level playing field — a $CO_2$ emissions price for all fuels without subsidies or other preferential policy treatment — maximizes the value to society of the large U.S. natural gas resource. Even under the pressure of an assumed $CO_2$ emissions policy, total U.S. natural gas use is projected to increase in magnitude up to 2050. Under a scenario with 50 percent $CO_2$ reductions to 2050, using an established model of the global economy and natural gas cost curves that include uncertainty, the principal effects of the associated $CO_2$ emissions price are to lower energy demand and displace coal with natural gas in the electricity sector. In effect, gas-fired power sets a competitive benchmark against which other technologies must compete in a lower carbon environment."*

The study also shows displacing inefficient electric generating plants (heat rate greater than 10,000) with natural gas combined cycle units has the potential to reduce $CO_2$ emissions by a factor of three while cautioning new pipelines and natural gas storage would likely be needed to supply fuel to these plants. If natural gas generation can be used to complement variable renewable generation, environmental benefits are also obtainable.

## *Energy Security Benefits*

Today, there is growing interest in achieving security of our energy infrastructure. Oil provides a significant proportion of the energy used in North America, the majority of which comes from foreign sources. The domestic supply of natural gas has been recognized as being in excess of 100 years of the current usage in North America resulting in the forecasting of stable prices for the foreseeable future; whereas, the world oil prices are rising, in part due to the devaluation of U.S. currency. This has resulted in a decoupling of the relative pricing between natural gas and oil in recent years; the decoupling is expected to continue. One of the favorable outcomes anticipated from this trend is an increase in the use of natural gas in new markets that have traditionally been served by liquid fuels.

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[11] *"The Future of Natural Gas, an Interdisciplinary MIT Study, Interim Report," MIT Energy Initiative, Massachusetts Institute of Technology, 2010.*

## Recommendations for Action

Achieving the vision in the long term will require a number of near term actions related to policy, technology development, and implementation of key capabilities in each of the industry sectors.

### *FOR POLICYMAKERS:*

#### *Research and Development/Budget*

- Include natural gas in advanced metering infrastructure development to optimize common infrastructure, interoperability and cross-compensation among all utility infrastructures including electricity and water;
- Ensure that future federal funding programs including Smart Grid encourage and allow the use of funding for dedicated natural gas projects and combined electric/natural gas projects;
- Develop a technology roadmap for natural gas in a smart energy future, including critical input from a broad group of stakeholders and the energy technology R&D community;
- Increase governmental funding for basic as well as applied research in natural gas safety and reliability and smart energy infrastructure technology; and
- Establish a governmental public-private research, development and deployment program for natural gas similar in size to the electric Smart Grid programs that includes component and system suppliers.

#### *Regulatory*

- Expand the use of source energy standards to recognize the value of full-fuel-cycle energy efficiency and carbon emission benefits and incorporate full-fuel-cycle analysis in all conservation and energy efficiency standards, including common measures of energy and greenhouse gas emissions;
- Expand ongoing Smart Grid standards development efforts to include natural gas;
- Provide consumers information about energy usage and energy appliance selections so they can make educated decisions.
- Modify the International Green Construction Code to ensure that every new building has access to natural gas service where available;
- Modify market rules to facilitate and create procedures for direct communications between pipeline and electric grid operators to fully optimize the usage of energy.
- Promote real-time communications between the gas and electricity grids;
- Approve projects in a timely manner to ensure natural gas infrastructure can meet the needs of all current and future end-uses; and
- Make energy efficiency programs neutral with respect to energy sources, and encourage collaboration among all energy providers.

### *FOR INDUSTRY:*

#### *Enhance or Create Capabilities for Supply*

- Create and expand real-time communications between the gas and electricity grids;

- Enhance systems to manage natural gas supply for fast-ramping generation to complement variable renewable resources and provide ancillary services; and
- Actively engage federal, provincial, and state regulators to help resolve the issues related to developing shale gas as a long-term energy source.

### *Enhance or Create Capabilities for Delivery*

- Ensure the natural gas infrastructure can meet the needs of all current and future end-uses;
- Enhance the system capability to accept and distribute a wide range of renewable gas sources;
- Ensure current and future natural gas infrastructure can accommodate emerging technologies, peak demand, energy efficiency programs, and new sources of supply; and
- Create or enhance capabilities to improve natural gas asset utilization on a real-time basis.

### *Enhance or Create Capabilities for End Use*

- Develop cost effective systems to be used to moderate peak electricity demand by using natural gas powered cooling solutions in the commercial applications and natural gas powered DG/CHP systems on an aggregated basis or as part of a microgrid for residential and/or commercial consumers;
- Advocate the use of DG/CHP systems to supply power, heat and cooling at industrial and commercial applications;
- Develop hybrid electric/natural gas appliances capable of providing space conditioning, water heating, cooking, and clothes drying; and
- Provide customers the information to make educated choices about their energy usage and energy appliance selections.

# Appendix: A Framework for Assessing the Benefits of Integrating Natural Gas with the Smart Grid

## *Context*

The vision for natural gas in a smart energy future assumes the natural gas can be utilized as a smart energy resource for homes and businesses, and as a strategic resource for electricity. This means:

- Natural gas must be available where it is needed in sufficient quantity and quality, even as new end uses increase, including electricity production;
- The natural gas infrastructure must continue to be safe, highly reliable and secure;
- The natural gas infrastructure must continue to support the production and delivery of natural gas efficiently and cost effectively, even as the system is expanded and becomes more complex; and
- Natural gas will play an increasingly important role as a resource for reducing $CO_2$ emissions.

Achieving all of this will require a level of capability and functionality that does not exist today, but can be implemented in the coming years. The following framework has been developed to illustrate which capabilities are most important to achieving the benefits.

## *Approach*

The approach used to develop this framework is similar to the approach used in similar benefits assessment work conducted by Navigant for the electric Smart Grid.[12] This is:

- Clarify the objectives or needs for enhancing the capability of the infrastructure;
- Identify the basic functionality that would support this capability;
- Determine the benefits that could result from implementing this functionality, and to whom the benefits accrue; and
- Define the relationships between the functions and the benefits.

In developing this framework for natural gas in a smart energy future, the GTI-Navigant team conducted numerous in-depth interviews with staff from natural gas companies around North America. The goal of these interviews was to identify important issues and challenges for the natural gas infrastructure in the future. Conversations during these interviews ranged from ensuring the safety and reliability of the gas system, to enhancing the overall efficiency of the energy value chain, to increasing operational efficiency, to enabling the use of renewable forms of energy. The information obtained during these interviews, along with information from GTI-Navigant subject matter experts, was organized and distilled into the framework presented here.

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[12] *Similar approaches were used for supporting the US Department of Energy and the California Energy Commission in assessing the benefits of electric smart grid systems and technology.*

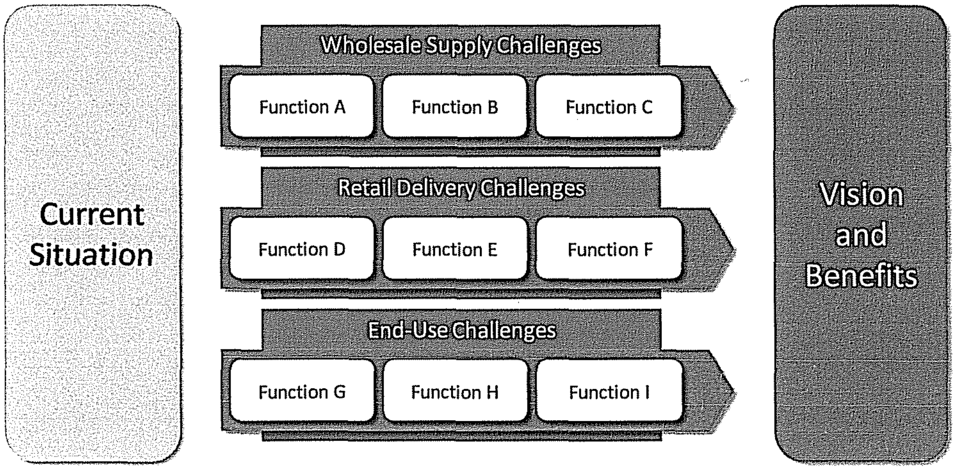

*Figure A-1. Functions enable the vision and its associated benefits.*

## Framework

### Objectives

The objectives for the enhancing the capability of the natural gas infrastructure come from the objectives of the smart energy future described in the white paper. Our energy resources and infrastructure in North America should be:

- Clean and sustainable;
- Reliable and secure;
- Affordable and efficient; and
- Robust and flexible.

### Functions

Functions, as used in this framework, are desired actions or capabilities. A function can be implemented in different ways depending on the way it is utilized. Functions are not technologies or systems, although they are related to them. Functions can remain relevant as technology evolves.

Twenty functions were developed that describe specific natural gas system capabilities that would contribute to achieving the objectives identified previously.

*Table A-2. Definitions of Natural Gas Functions.*

| FUNCTIONS | DESCRIPTION |
|---|---|
| **Automated High Ramp Rate Supply Response** | Provide natural gas at the pressures and volumes required to efficiently operate fast ramp rate generating facilities connected to electric and natural gas transmission through an infrastructure equipped with sensing and controlling technology to allow real-time response. |
| **Wide Area Monitoring, Visualization, and Control** | Use 2-way communications technologies to collect, analyze and interpret transmission supply data resulting in information that is then used by visualization and control technology providing proactive responses for predicated events and real-time reactive response for unforeseen events. |
| **Peak Electric Demand Management** | Monitor and proactively provide appropriate peak load reduction and/or demand response through direct use, the use of dual fuel appliances or local generation measures to requests triggered by the events on the electric grid. |
| **Predictive Load Modeling and Forecasting** | Use of current customer load data in combination with historical load data, current and historic weather data and current and historic major customer use patterns to provide trend analysis that allows accurate load prediction and forecasting by modeling software. |
| **Real Time Inter-grid Communications (Gas/Electric)** | Two-way, secure, redundant path communications that leverage backhaul options to provide real-time data that can be acted upon by artificial intelligence system and/or system operators resulting in coordinated operations between the electric and gas grids. |
| **Automated/Dispatchable Market Area Storage** | Large volume storage available for immediate response to support the continued operations of the natural gas system. |
| **Gas Supply Quality Monitoring and Management** | Sensors and other real-time monitoring devices that provide BTU, compositional and trace constituent analysis to allow system-wide quality management. |
| **BTU Composition Monitoring at Custody Exchange (Billing)** | Calorific monitoring coupled with volume and pressure sensing to ensure the supplier and customer that contract obligations are met. |
| **Remote Cathodic Protection Monitoring and Reporting** | Real-time system monitoring of cathodic protection installations that report changes or the loss of capability, eliminating or significantly reducing site visit obligations. |
| **Automated Leak Detection and Notification** | Real-time monitoring and reporting of methane/ethane levels to a system capable of verifying customer contacts and allowing operators to determine if action is required. |
| **Detection/Predictive Third Party Damage** | A system that uses a combination of visual and/or proximity sensing based artificial intelligence to proactively notify operations staff of a potential incident that could result in damage or of an occurrence of recent damage. |
| **Automated Flow Control and Volume/Pressure Mgmt and Real-Time Load Balancing (Re-routing)** | Sensing technology capable of monitoring and reporting volume and pressure that can be acted upon by artificial intelligence systems or system operators. This includes communications technologies coupled with monitoring and control technologies that use real-time information on volume, pressure and quality to maintain system operations. This includes opening and closing valves. |
| **Automated Meter Reading (AMR)** | Advanced meters coupled with communications capability to record and report use data. This includes turn-on/turn-off cost, and collections. |
| **Real-time Load Measurement and Management** | Smart gas metering and load management devices in the customer premise that allow the LDC to monitor and manage customer load and end use appliances. This may include real-time metering, remote disconnection, outage detection and other features. |

| | |
|---|---|
| **Remote Meter Shut-off** | Use of 2-way communications to stop flow through a meter to improve safety, reduce the need for site visits or to assist with non-payment. |
| **Remote Meter Turn-on** | Use of 2-way communications to re-establish flow through a meter following a proper response to a safety related event, to reduce the need for site visits or to re-establish service for a customer. |
| **Automated Distribution Shut-off** | The use of a combination of sensors and communications technologies located strategically throughout the distribution network capable of detecting and reporting incidents that would warrant activating one-or more control devices and providing the data on a real-time basis to be acted upon by an artificial intelligence system and/or a system operator. |
| **Automated Transmission Shut-off** | The use of a combination of sensors and communications technologies located strategically throughout the transmission network capable of detecting and reporting incidents that would warrant activating one-or more control devices and providing the data on a real-time basis to be acted upon by an artificial intelligence system and/or a system operator. |
| **Customer Premise Energy Use Optimization** | A simple, easy to use and convenient in-home display and/or a smart thermostat capable of 2-way communications with utilities to receive demand response requests or TOU rate information as well as every major energy using device that provides the customer with plain language site specific choices for energy use and carbon footprint. |
| **Measurement and Verification of Energy Efficiency** | The use of sensing and communicating technology to provide a positive method of indicating an energy efficient request was responded to by one or more measurable actions on the part of the customer. |

### Benefits

Implementing the functions described above will have a significant impact on the configuration and operation of the energy infrastructure in North America. The increased level of performance will yield benefits in four fundamental categories:

- Economic – reduced costs, or increased production at the same cost, that result from improved utility system efficiency and asset utilization;
- Reliability and Service Quality – reduction in interruptions and service quality events;
- Environmental – reduced impacts of climate change and effects on human health and ecosystems; and
- Energy Security and Safety – improved energy security (i.e., dependence on foreign sources), and reductions in injuries, loss of life and property damage.

Within each category are several sub-categories and specific benefits, and each benefit can be derived from multiple sources. While the same, or similar, benefit can be realized within multiple industry sectors, most specific benefits are focused primarily in one sector (supply, delivery, or end use).

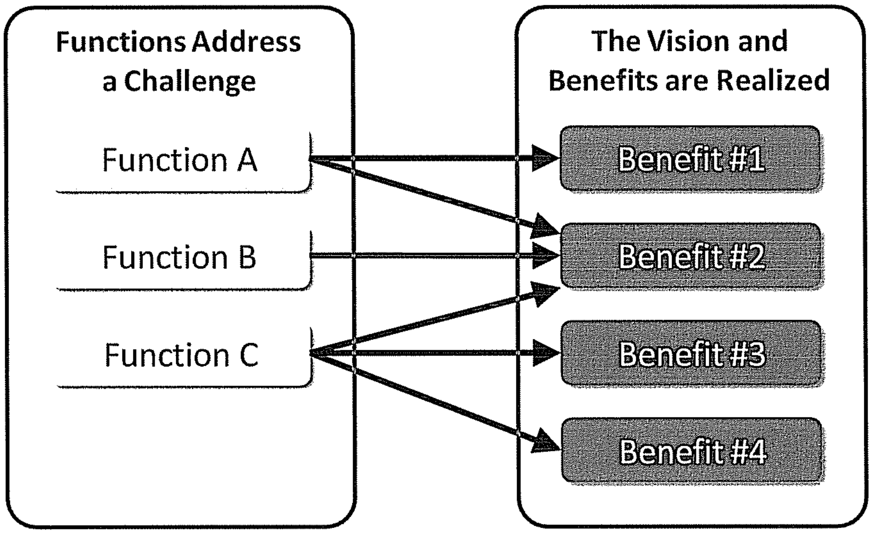

*Figure A-2. Functions lead to benefits.*

Recall from *Figure A-1* that functions enable achieving the vision and its associated benefits. Depending on the function, it can contribute to more than one benefit (*Figure A-2*). For example, implementing Remote Meter Turn-off can lead to multiple benefits including reduced operations cost, reduced $CO_2$ emissions from fewer utility vehicle miles being required for daily operations and maintenance, and improved public and utility worker safety. It is also possible for one benefit to be supported by multiple functions. For example, several functions, including Automated Leak Detection and Notification, Detection/Prediction of Third Party Damage, and Automated Distribution Shut-off, all contribute to the benefit of improved public safety.

*Table A-3. Benefit Categories and Benefits.*

| | |
|---|---|
| **Economic Benefits** | |
| **Improved Asset Utilization** | Optimized Electricity Generation Operation |
| | Deferred Electricity Generation Capacity Investments |
| | Improved Pipeline Capacity Usage |
| **Gas Transmission and Distribution (T&D) Capital Savings** | Deferred Transmission Capacity Investments |
| | Deferred Distribution Capacity Investments |
| | Reduced Equipment Failures |
| **Gas T&D O&M Savings** | Reduced T&D Maintenance Cost |
| | Reduced T&D Operations Cost |
| | Reduced Meter Reading Cost |
| **Theft Reduction** | Reduced Gas Theft |
| **Energy Efficiency** | Reduced Lost and Unaccounted For Gas |
| **Energy Cost Savings** | Reduced Energy Costs (to consumers) |
| **Reliability Benefits** | |
| **Service Interruptions** | Reduced Gas Interruptions to Consumers |
| | Reduced Electric Interruptions to Consumers |
| **Service Quality** | Reduced Pressure Drops |
| **Safety Benefits** | |
| **Safety** | Reduced Public Safety Incidents |
| | Reduced Utility Worker Incidents |
| **Environmental Benefits** | |
| **Air Emissions** | Reduced $CO_2$ Emissions |
| | Reduced $SO_x$, $NO_x$, and PM-2.5 Emissions |
| **T&D Gas Emissions** | Reduced Gas Leakage |
| **Security Benefits** | |
| **Energy Security** | Reduced Oil Usage |
| | Stabilized Energy Price |
| | Reduced Wide-scale Blackouts |

*Table A-4. Definitions of Benefits.*

| Benefit | Definition |
|---|---|
| **Optimized Electricity Generation Operation** | Better forecasting and monitoring of load and grid performance would enable grid operators to dispatch a more efficient mix of generation that could be optimized to reduce cost. The coordinated operation of energy storage or plug-in electric vehicle assets could also result in completely avoiding central generation dispatch. |
| **Deferred Electricity Generation Capacity Investments** | Utilities and grid operators ensure that generation capacity can serve the maximum amount of load that planning and operations forecasts indicate. However, this capacity is only required for very short periods each year, when demand peaks. Reducing peak electricity demand and flattening the load curve should reduce the generation capacity required to service load, and lead to cheaper electricity for customers. |
| **Improved Pipeline Capacity Usage** | Improved forecasting and communications between suppliers and consumers will allow pipeline companies to better match nominations and deliveries, increasing the throughput and value of every pipeline. |
| **Deferred Transmission Capacity Investments** | Reducing the load and stress on transmission pipelines increases asset utilization and reduces the potential need for upgrades. Closer monitoring, rerouting gas flow, and reducing pressure could enable utilities to defer upgrades on lines and transformers. |
| **Deferred Distribution Capacity Investments** | As with the transmission system, reducing the load and stress on distribution elements increases asset utilization and reduces the potential need for upgrades. Closer monitoring and load management on distribution feeders could potentially extend the time before upgrades or capacity additions are required. |
| **Reduced Equipment Failures** | Reducing mechanical stresses and deterioration on equipment increases service life and reduces the probability of premature failure. This can be accomplished though enhanced monitoring and detection, enhanced pressure management, or loading limits based on real-time equipment or environmental factors. |
| **Reduced T&D Maintenance Cost** | The cost of sending technicians into the field to check equipment condition is high. Moreover, to ensure they maintain equipment sufficiently, and identify failure precursors, some LDCs may conduct equipment testing and maintenance more often than is necessary. Online diagnosis and reporting of equipment condition would reduce or eliminate the need to send people out to check equipment resulting in a cost savings. |
| **Reduced T&D Operations Cost** | Automated or remote controlled operation of valves and other distribution equipment eliminates the need to send a line worker or crew to the switch location in order to operate it. This reduces the cost associated with the field service worker(s) and service vehicle. |
| **Reduced Meter Reading Cost** | Minimizing the time spent reading meters manually leading to reduced meter operations costs. Some technologies can also reduce costs associated with other meter operations such as connect/disconnect, outage investigations, and maintenance. |
| **Reduced Gas Theft** | Smart meters can typically detect tampering. Moreover, a meter data management system can analyze customer usage to identify patterns that could indicate diversion. These new capabilities can lead to a reduction in gas theft through earlier identification and prevention of theft. |
| **Reduced Lost and Unaccounted For Gas** | Better sensors and control technology will reduce the amount of gas that is lost. |
| **Reduced Gas Interruptions to Consumers** | The monetary benefit of reducing sustained outages is based on the value of service (VOS) of each customer class. The VOS parameter represents the total cost of a power outage per MWh. This cost includes the value of unserved energy, lost productivity, collateral damage, administrative costs, the value of penalties and performance based rates. Functions that lead to this benefit can reduce the likelihood that there will be an outage, allow the system to be reconfigured on the fly to help restore service to as many customers as possible; and, enable a quicker response in the restoration effort. |

| | |
|---|---|
| **Reduced Electric Interruptions to Consumers** | A sustained outage is one lasting > 5 minutes, excluding major outages and wide-scale outages. The monetary benefit of reducing sustained outages is based on the VOS of each customer class. The VOS parameter represents the total cost of a power outage per MWh. This cost includes the value of unserved energy, lost productivity, collateral damage, administrative costs, the value of penalties and performance based rates. Functions that lead to this benefit can reduce the likelihood that there will be an outage, allow the system to be reconfigured on the fly to help restore service to as many customers as possible, enable a quicker response in the restoration effort, or mitigate the impact of an outage through islanding or alternative power supply. |
| **Reduced Pressure Drops** | Better managing gas volume and pressure will help reduce incidents of low pressure that may affect consumer service levels. For some sensitive consumers, a pressure drop can be as disruptive as an interruption of service. |
| **Reduced Public Safety Incidents** | Sensors, communications, information processors and control devices can detect and respond to conditions compromising the safety of utility workers and the public. |
| **Reduced Utility Worker Incidents** | Automation and remote control can reduce the need for service workers to perform manual operations in the field, reducing the chance of traffic incidents and work-related hazards. |
| **Reduced $CO_2$ Emissions** | Functions providing this benefit can lead to avoided vehicle miles, decrease the amount of central generation needed to their serve load (through reduced electricity consumption, reduced electricity losses, more optimal generation dispatch), and or reduce peak generation. These impacts translate into a reduction in $CO_2$ emissions produced by fossil-based electricity generators and vehicles. |
| **Reduced $SO_x$, $NO_x$, and PM-2.5 Emissions** | Functions providing this benefit can lead to avoided vehicle miles, decrease the amount of central generation needed to their serve load (through reduced electricity consumption, reduced electricity losses, more optimal generation dispatch), and or reduce peak generation. These impacts translate into a reduction in pollutant emissions produced by fossil-based electricity generators and vehicles. |
| **Reduced Gas Leakage** | By ensuring the integrity of the gas infrastructure, and by avoiding over-pressure, less gas will leak. This reduces the amount of gas lost, but also reduces the emission of methane, a potent greenhouse gas. |
| **Reduced Oil Usage** | The functions that provide this benefit eliminate the need to send a service worker or crew to the valve or compressor locations in order to operate them, eliminate the need for truck rolls to perform diagnosis of equipment condition, and reduce truck rolls for meter reading and measurement purposes. This reduces the fuel consumed by a service vehicle or line truck. The use of natural gas vehicles (NGVs) can also lead to this benefit since the electrical energy used by NGVs displaces the equivalent amount of oil. |
| **Stabilized Energy Price** | Integrating natural gas for use by homes and businesses, and also for electricity generation will tend to reduce volatility in energy supply, and thereby reduce price volatility and increase energy options. |
| **Reduced Wide-scale Blackouts** | The functions that lead to this benefit will give grid operators a better picture of the bulk power system, and allow them to better coordinate resources and operations between regions. This will reduce the probability of wide-scale regional blackouts. |

### *Relationships between Natural Gas Functions, Benefits and the Vision*

As described above, functions lead to benefits and enable the vision. The tables on the following pages illustrate these relationships.

*Table A-5.* Mapping of Relationships between Natural Gas Infrastructure Functions and Benefits
*Table A-6.* Mapping of Relationships between Natural Gas Infrastructure Functions and the Vision

*Table A-5. Mapping of Relationships between Natural Gas Infrastructure Functions and Benefits*

| Benefits Derived from Implementing Functions | | | Natural Gas Infrastructure Functions | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Automated High Ramp Rate Supply Response | Wide Area Monitoring, Visualization, and Control | Peak Electric Demand Management | Predictive Load Modeling and Forecasting | Real Time Inter-grid Communications (Gas/Electric) | Automated/Dispatchable Market Area Storage | Gas Supply Quality Monitoring and Management | BTU Composition Monitoring at Custody Exchange (Billing) | Remote Cathodic Protection Monitoring and Reporting | Automated Leak Detection and Notification | Detection/Prediction of Third Party Damage | Automated Flow Control and Volume/Pressure Mgmt and Real-Time Load Balancing (Re-routing) | Automated Meter Reading (AMR) | Real-time Load Measurement and Management | Remote Meter Shut-off | Remote Meter Turn-on | Automated Distribution Shut-off | Automated Transmission Shut-off | Customer Premise Energy Use Optimization | Measurement and Verification of Energy Efficiency |
| Economic | Improved Asset Utilization | Optimized Electricity Generation Operation | ○ | | | | ○ | ○ | | | | | | ○ | | | | | | | | |
| | | Deferred Electricity Generation Capacity Investments | ○ | | | | ○ | | | | | | | | | | | | | | | |
| | | Improved Pipeline Capacity Usage | | | | ○ | | | | | | | | | | | | | | | | |
| | Gas T&D Capital Savings | Deferred Transmission Capacity Investments | | ○ | | | ○ | ○ | | | | | | | | | | | | | | |
| | | Deferred Distribution Capacity Investments | | | ○ | ○ | | | | | | | | ○ | | ○ | | | | | | |
| | | Reduced Equipment Failures | | | | | | | ○ | | | | | | | | | | | | | |
| | Gas T&D O&M Savings | Reduced T&D Maintenance Cost | | | | | | | ○ | | | ○ | | | | | | | ○ | ○ | | |
| | | Reduced T&D Operations Cost | | | | | | | | ○ | | | | ○ | | | ○ | ○ | ○ | ○ | | |
| | | Reduced Meter Reading Cost | | | | | | | | | | | | | ○ | | ○ | ○ | | | | |
| | Theft Reduction | Reduced Gas Theft | | | | | | | | | | | | | | ○ | ○ | | | | | |
| | Energy Efficiency | Reduced Lost and Unaccounted For Gas | | | | | | | | | | ○ | | | | | | | ○ | ○ | | |
| | Energy Cost Savings | Reduced Energy Costs (to customers) | | | ○ | | | | | | | | | | | | | | | | ○ | |
| Reliability | Service Interruptions | Reduced Gas Interruptions to Customers | | ○ | | | | ○ | | | | | | ○ | | | | | ○ | ○ | | |
| | | Reduced Electric Interruptions to Customers | | | | | | | | | | | | | | | | | | | | |
| | Service Quality | Reduced Pressure Drops | | | | | ○ | ○ | | | | | | | | | | | | | | |
| Safety | Safety | Reduce Public Safety Incidents | ○ | | | | | | | | ○ | ○ | ○ | | | | ○ | | ○ | ○ | | |
| | | Reduce Utility Worker Incidents | | | | | | | | | ○ | ○ | ○ | | ○ | | ○ | ○ | ○ | ○ | | |
| Environmental | Air Emissions | Reduced $CO_2$ Emissions | | | | | | | | | | | | | | | | | | | | |
| | | Reduced $SO_x$, $NO_x$, and PM-2.5 Emissions | | | | | | | | | | | | | | | | | | | | |
| | T&D Gas Emissions | Reduced Gas Leakage | | | | | | | | | | ○ | | | | | | | | | | |
| Security | Energy Security (not monetized) | Reduced Oil Usage | | | | | | | | | | | | | | | | | | | | |
| | | Stabilized Energy Price | ○ | | ○ | | | | | | | | | | | | | | | | | |
| | | Reduced Wide-scale Blackouts | ○ | | | | ○ | ○ | | | | | | | | | | | | | | |

*○ signifies that the Function contributes a benefit*

### Table A-6. Mapping of Relationships between Natural Gas Infrastructure Functions and the Vision

| **The Vision for Natural Gas in a Smart Energy Future**<br>Natural gas is an abundant, domestic, low-carbon resource for electricity, and a smart energy source for homes and businesses. Smarter natural gas systems result in a secure, reliable and efficient energy infrastructure for North America, and enable smarter electric grids. | | Natural Gas Infrastructure Functions | | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Automated High Ramp Rate Supply Response | Wide Area Monitoring, Visualization, and Control | Peak Electric Demand Management | Predictive Load Modeling and Forecasting | Real Time Inter-grid Communications (Gas/Electric) | Automated/Dispatchable Market Area Storage | Gas Supply Quality Monitoring and Management | BTU Composition Monitoring at Custody Exchange (Billing) | Remote Cathodic Protection Monitoring and Reporting | Automated Leak Detection and Notification | Detection/Predictive Third Party Damage | Automated Flow Control and Volume/Pressure Mgmt and Real-Time Load Balancing (Re-routing) | Automated Meter Reading (AMR) | Real-time Load Measurement and Management | Remote Meter Shut-off | Remote Meter Turn-on | Automated Distribution Shut-off | Automated Transmission Shut-off | Customer Premise Energy Use Optimization | Measurement and Verification of Energy Efficiency |
| **Supply**<br>Improved communication between supply and electric generation, including variable renewable resources, is effectively used to enhance responsiveness and operation of the electric grid. | Actively managed natural gas supply responds to fluctuations in electricity production. Fast-ramping gas fired power generation is integrated with variable renewable resources to ensure a reliable and secure electricity supply. | ● | | | | ● | ● | | | | | | ● | | | | | | | | |
| | Demand forecasts for electricity are available to gas suppliers, helping ensure that fuel is available when and where it is needed. Energy market information is available, allowing tighter coordination between pipeline and grid operators. | | ● | | ● | | | | | | | | | | | | | | | | |
| | Direct communications between pipeline and grid operators is possible, and real-time information about weather, demand, infrastructure and operating conditions is shared. | | | | | ● | | | | | | | | | | | | | | | |
| **Delivery**<br>Communications and intelligent field devices are effectively used to enhance safety and efficiency of the network and accommodate new end uses and supply sources. | Robust and flexible infrastructure responds to consumer needs and enables local distribution companies (LDCs) to safely and efficiently increase capacity and actively manage volume and pressure using a network of sensors, two-way communications, and automation. This infrastructure readily accommodates diverse sources of supply such as renewable and shale gas. | | | | | | ● | ● | ● | | | | ● | | ● | ● | ● | ● | ● | | |
| | Optimized investment is possible as better load forecasts, network monitoring and demand management techniques are employed to improve asset utilization, capital deployment and increase useful life. | | | | ● | | ● | | | ● | ● | ● | ● | | ● | | | | | | ● |
| | Emerging technologies such as distributed generation, microgrids, thermal grids and alternatively-fueled vehicles are creating new uses for natural gas and electricity. | | | ● | | | | | | | | | | | | | | | | ● | |
| **End Use**<br>Comparable attributes of various energy sources are established and made available to consumers, allowing them to make informed decisions and better choices about energy use. | Transparent, repeatable analyses are done for multiple energy sources that directly compare attributes such as energy content, price, and environmental quality on a full fuel cycle basis. | | | | | | | | | | | | | | | | | | | ● | |
| | Comparable energy attribute information is available to customers in a form that is simple and convenient. | | | | | | | | ● | | | | | | | | | | | ● | |
| | Energy management tools provide timely intelligence that aids consumers in making energy choices. | | | ● | | | | | | | | | | | | | | | | ● | ● |

● signifies that the Function supports the Vision

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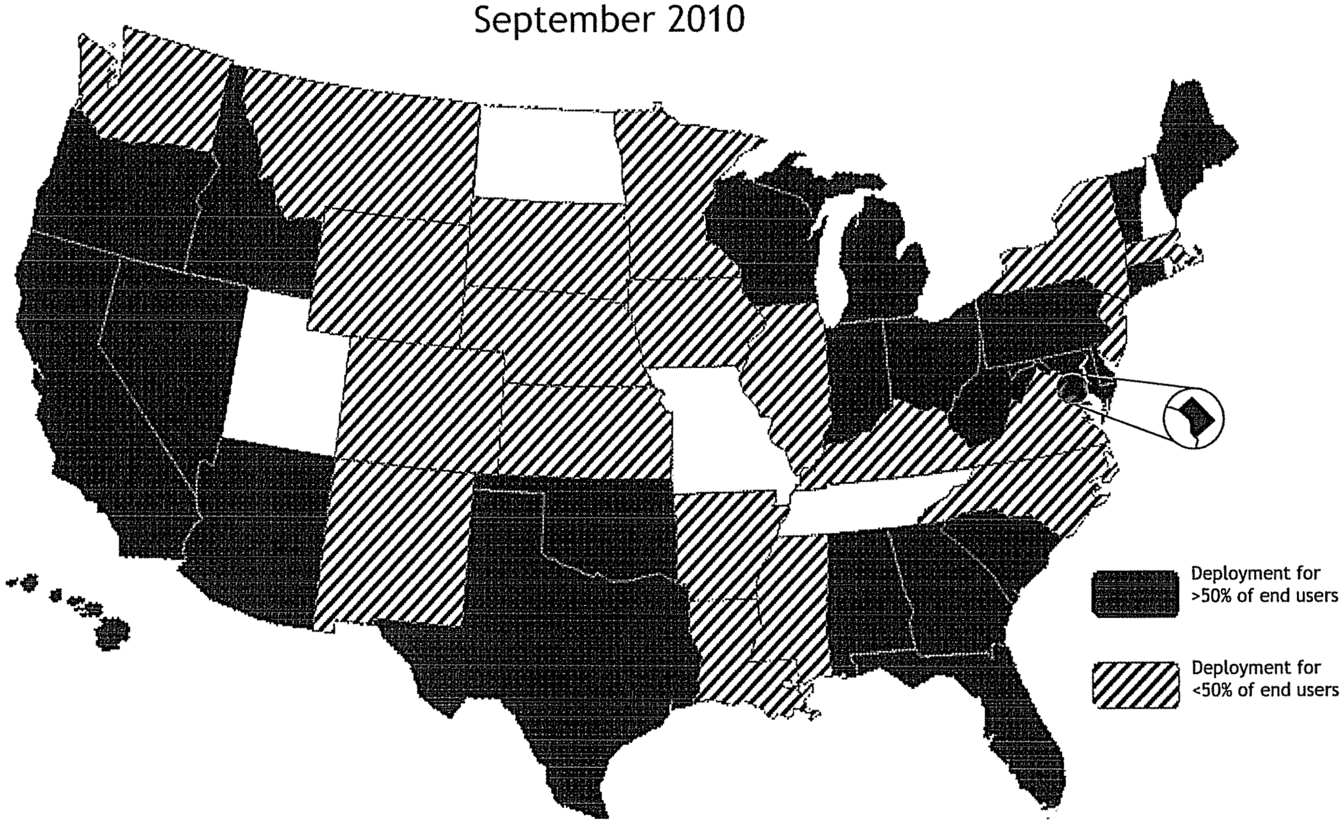
# APPENDIX D: UTILITY-SCALE SMART METER DEPLOYMENTS, PLANS & PROPOSALS

The EDISON FOUNDATION | INSTITUTE FOR Electric Efficiency

# Utility-Scale Smart Meter Deployments, Plans & Proposals

## September 2010



This map and table summarize smart meter deployments for mass market customers, planned deployments, and proposals by investor-owned utilities and large public power utilities. Note that smart meter deployments by rural electric cooperatives, though extensive, are not included. IEE estimates that approximately 65 million smart meters will be deployed by 2020, representing 50% of U.S. households.

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **AEP**[1] | IN, KY, MI, OH, OK, TX, VA, WV | 5,200,000 | AEP plans to deploy smart meters to 5.2 million customers served by their Operating Companies. To-date, AEP's Indiana Michigan Power (I&M) subsidiary has deployed 10,000 meters to customers in South Bend, IN; AEP Ohio has deployed 100,000 in the Columbus OH area; AEP Texas has deployed 24,000 meters, with specific plans for another 900,000 installations by 2013; and AEP's Public Service Company of Oklahoma (PSO) has specific plans for deployment of 13,200 meters in Owasso, OK. Timing for the remaining deployments will depend on specific conditions in each of the seven operating company subsidiaries. | AEP Corporate Sustainability Report 2009[2]; AEPOhio.com[3]; AEP.com[4] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **Allegheny Power** | MD, PA, WV | 701,000 | Allegheny launched pilots in Morgantown, WV and Urbana, MD to test smart meters and thermostats (1,140 meters installed). In PA, Act 129 (2008) requires electric distribution companies with more than 100,000 customers to file a smart meter technology procurement and installation plan for Commission approval. Allegheny's plan to deploy smart meters throughout their service territory was rejected in October 2009 and a revised smart meter plan is currently being drafted. | Allegheny Power 2008 Annual Report[5], MD H.B. 1072 |
| **Allete (d/b/a Minnesota Power)*** | MN | 8,000 | Allete plans to invest $3M and deploy 8,000 smart meters in northeast Minnesota. The utility also intends to purchase automation equipment and begin a dynamic pricing program. $1.5M of the project cost is covered by federal funds. | Minnesota St. Paul Business Journal[6] |
| **Alliant Energy** | IA, MN, WI | 1,400,000 | Deployment began in WI in 2008, currently 500,000 meters are deployed with expected completion by 2012 | emeter.com[7] |
| **Ameren** | IL | 1,100,000 | Ameren began their smart meter deployment in 2006 and reached 50% of their installation target by June 2008. Full deployment is expected by 2011-12. Ameren operations in Missouri manage 1M meters capable of remote readings. | smartmeters.com[8] |
| **Austin Energy** | TX | 410,000 | Austin Energy's smart meter program was approved in 2008, full deployment is underway and is expected to reach completion in 2010. | greentechgrid.com[9] |
| **Avista Utilities** | ID, WA | 14,000 | Avista plans to install 14,000 smart meters in Pullman, WA as part of a 5-state demonstration project leveraging DOE SGDG funds. | allbusiness.com[10] |
| **AZ Public Service** | AZ | 1,000,000 | APS expects completion of their smart meter investments in 2012. As of June 2010 over 400,000 are already in place in the Phoenix area. APS customers can enroll in the Time Advantage Plan, a time-of-use (TOU) rate structure. | APS news release[11];<br>Arizona Department of Commerce[12]; |
| **Baltimore Gas & Electric** | MD | 1,200,000 | BG&E began with a smart meter pilot of 3,000 meters in 2008 and was awarded $200M in SGIG funds ($452M total project value) to deploy 1.2M residential smart meters, coupled with dynamic pricing. The utility aims to deploy smart meters throughout their service territory with a planned completion date of 2014. Reimbursement for installation will not occur until 2014 pending commission approval. | Constellation (BG&E) press release[13];<br>Baltimore Sun[14] |
| **Bangor Hydro-Electric** | ME | 120,000 | BHE has deployed 2-way smart meters to 97% of their service territory and plan to complete deployment to the remaining 3% in 2009-10. | www.bhe.com[15];<br>Email correspondence (04/17/09) |
| **Black Hills/ Colorado Electric Utility Co.** | CO | 98,500 | Black Hills has installed 56,500 smart meters and intends to install an additional 42,000 meters along with supporting communications infrastructure in their service territory, bringing the total number of installed smart meters to 98,500. The utility received $6.1M in SGIG funds ($12.2M total project value). | smartgrid.tmcnet.com[16] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **Black Hills Power** | SD | 69,000 | Black Hills Power will install a total of 69,000 meters within its service territory by Spring 2011, with 40,000 installed by the end of 2010. The utility was awarded $9.6M in SGIG matching funds to install smart meters, upgrade ICT infrastructure, and other equipment. The infrastructure upgrades will also benefit customers in MN. | smartgrid.tcmnet.com[17] |
| **CenterPoint** | TX | 2,200,000 | CenterPoint Houston received approval in 2008 to install an advanced metering system across its service territory, and was awarded $200M in SGIG funds ($639M total project value) to support the deployment effort. As of June 30, 2010 CenterPoint had installed 450,000 meters. | CenterPoint 2008 Annual Report[18]; Navigant Consulting[19] |
| **Central Maine Power Company** | ME | 650,000 | Central Maine Power Company intends to install a smart meter network for all customers in their service territory. The utility was awarded $96M in SGIG funds ($192M total project value) to assist with the planned installation. | Central Maine Power Company press release[20] |
| **Central VT Public Service/VT Transco** | VT | 300,000 | Central VT Public Service/VT Transco intends to expand the number of installed smart meters from 28,000 to 300,000. The utility was awarded $69M ($138M total project value) in SGIG funding for the meter installation and the development of additional demand response programs. | CVPS press release[21] |
| **Cheyenne Light** | WY | 38,000 | Cheyenne Light plans to install 38,000 smart meters and make communication upgrades in and around Cheyenne, WY. The utility was awarded $5M in SGIG funding. | PR Newswire article[22] |
| **Cleco Power** | LA | 277,000 | Cleco Power intends to install a smart meter network for the utility's entire service territory pending approval from the Louisiana Public Service Commission. $20M in SGIG funds ($72.9M total project value) was awarded to the utility. | newsbanner.com[23] |
| **Commonwealth Edison** | IL | 130,000 | ComEd is running a pilot in the greater Chicago area with 130,000 smart meters installed in homes. An 8,000 household subgroup is testing different dynamic pricing, in-home display, and web-portal-based information options. | ComEd PowerPoint Presentation, IEE September 2010 meeting. |
| **Connecticut Light & Power** | CT | 1,200,000 | CL&P has filed plans to deploy smart meters to all 1.2 million of its customers between 2012 and 2016. Under the plan, all CL&P customers can select different dynamic pricing structures: TOU and CPP rates for all customers, and PTR for low income customers only. | CL&P website[24] |
| **Consolidated Edison** | NY | 1,500 | Con Ed is piloting a $6M smart grid program in northwest Queens. 300 eligible customers will test in-home displays that monitor energy usage by appliance. | Con Ed press release[25] |
| **Consumers Energy** | MI | 1,800,000 | In November 2008 Consumers signed an agreement with IBM to help plan, deploy, and test an AMI and field pilot network. By 2015 the utility anticipates converting its 1.8M electric customers to smart technology. | smartgridnews.com[26] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **CPS Energy** | TX | 700,000 | CPS intends to install a smart meter in every home within its territory by 2015. | smartgrid.tmcnet.com[27] |
| **DPL Inc.** | OH | 523,000 | DPL plans to install 523,000 2-way communication smart meters over a 10 year period for its residential customers at a cost of $500M. | Dayton Daily News[28] |
| **Dominion** | VA | 2,400,000 | Dominion has installed 7,000 smart meters in Midlothian and 48,000 in Charlottesville to test the technology, with plans to expand testing in Northern Virginia with a 30,000 meter installation. With commission approval, the utility plans for a systemwide installation of 2.4 million smart meters once testing is complete. | Richmond Times Dispatch[29] |
| **DTE** | MI | 4,000,000 | DTE initially tested 30,000 meters in Grosse Ile Township and developed a dynamic pricing pilot for 5,000 customers. DTE is supporting its "SmartCurrents" program with an additional deployment of 660,000 smart meters, supported by $84M in SGIG funds ($168M total project value). DTE intends to fully deploy smart meters in its service territory at a later date. | DTE press release[30]; annarbor.com article[31] |
| **Duke Energy** | KY, IN, OH, NC, SC | 1,500,000 | Duke has moved forward with smart meter deployment in Ohio afer receiving approval from the state commission in May 2010. As of September 2010 approximately 200,000 of the planned 700,000 meters have been installed. Duke filed with the Indiana Commission a revised pilot request for 40,000 meters to be installed in 2011 and intends to request full deployment (800,000 meters) at a later date. Duke was awarded $200M in SGIG funds for its grid modernization project that will support the deployment of 1.5M smart meters in Indiana and Ohio. | Duke press release[32]; PowerPoint presentation, IEE September 2010 meeting |
| **Entergy New Orleans** | LA | 11,500 | Entergy plans to pilot smart meters and dynamic pricing in low-income households in New Orleans. The utility was awarded $5M in SGIG funding ($10M total project value) to support this project. | Entergy New Orleans press release[33] |
| **FirstEnergy Corp** | OH, PA | 58,000 | FirstEnergy is moving forward with its Smart Grid Modernization Initiative as advanced metering infrastructure (AMI) was approved by the PUCO in June 2010. FirstEnergy Corp will use a $57.4M SGIG award and matching company money to install 5,000 residential smart meters in the Cleveland Electric Illuminating Company service territory by Summer 2010. Time-of-Use rates and other incentive programs will be piloted over a 3 year period. Another 39,000 meters could be installed later with cost recovery to be addressed at a later date. In York, PA, FirstEnergy seeks 14,000 customers to be volunteer participants in a two-way demand response system. | Public Utility Commission of Ohio press release[34]; cleveland.com[35] |
| **Hawaii Electric Company** | HI | 451,000 | HECO is planning to deploy smart meters throughout their service territory by mid-decade using company funding. HECO received a $5.4M SGIG award, however, their proposal did not include smart meter details. | Energy Efficiency News[36]; HECO press release[37] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **Idaho Power** | ID | 478,000 | Idaho Power engaged in a smart meter pilot in 2007 with full deployment to 478,000 customers expected by 2011. By the end of 2010, 334,000 Idaho Power customers will have smart meters. The utility received $47M ($94M total program cost) of SGIG funds to support the deployment effort. | Idaho Power press release[38] & AMI FAQ page[39]; Idaho Power AMI deployment map[40] |
| **Indianapolis Power & Light** | IN | 22,000 | As part of IPL's residential focused Smart Energy Project, 22,000 smart meters will be installed throughout IPL's service territory. IPL was awarded $20M in SGIG funds (total program cost, $48.78M) to deploy smart meters along with complementary technologies in their service territory. | IPL press release[41]; AllBusiness[42] |
| **Los Angeles Department of Water and Power** | CA | 76,500 | Los Angeles DWP intends to implement an AMI plan for 64,000 residential customers with monthly energy consumption over 1200 kWh; 10,000 high turn-over residencies; and 2,500 critical care residential customers by 2013. | California Energy Commission[43] |
| **JEA** | FL | 3,000 | JEA is moving forward with smart meters and will provide a dynamic pricing pilot and consumer engagement software for 3,000 customers. The utility was awarded $13M in SGIG funding for this project. | DOE Recovery Act[44] |
| **Louisville Gas & Electric** | KY | 2,000 | LG&E is in the third year of a Responsive Pricing and Smart Meter pilot program. 100 customers have time of use (TOU) pricing. | LGE POWERSource newsletter[45] |
| **Madison Gas & Electric** | WI | 1,750 | MGE is installing a small-scale smart grid network, including meters, EV charging stations, and in-home management systems. $5.5M in SGIG funds ($11M total project value) were awarded to the utility to support their efforts. | MGE press release[46]; DOE Recovery Act, Smart Grid[47] |
| **National Grid** | MA, NY | 54,400 | Under the MA Green Communities Act, all four utilities must submit plans for a smart grid pilot. National Grid's plan is currently being considered by the Commission and, if approved, would deploy 15,000 smart meters to customers in the Worcester area by summer of 2011. National Grid has also proposed a smart grid demonstration program in the Syracuse area, that includes a planned deployment of 39,400 meters at a cost of $123M | www.smartmeters.com[48]; Worcester Business Journal[49] |
| **NextEra Energy (formerly FPL)** | FL | 4,400,000 | NextEra Energy will move forward with FPL's Energy Smart Florida program, which includes 2.6M smart meters for customers in south Florida. FPL plans to deploy smart meters throughout their service territory with assistance coming from a $200M SGIG award. | Sun Sentinel[50] |
| **Nebraska Public Power District** | NE | 68,500 | NPPD is in the process of installing smart meters throughout the state. 68,500 smart meters will be installed by 2015. As of August 2010 a total of 29,000 meters have been installed. | NPPD AMI FAQ[51]; Smart Grid Investment Clearinghouse[52] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **NSTAR** | MA | 2,800 | NSTAR is installing 2,800 smart meters in Newton, Hopkinton, and Jamaica Plains as part of a $16M pilot project approved by the Massachusetts Public Utilities Commission. The project is expected to run through 2012. NSTAR's investments satisfy the 2008 Green Communities Act requirement that all public utilities in Massachusetts develop and implement a smart grid pilot. | smartmeters.com[53];<br>NSTAR press release[54] |
| **NV Energy** | NV | 1,450,000 | NV Energy received approval from the Public Utilities Commission of Nevada on July 28, 2010 to go forward with their Advanced Service Delivery (ASD) allowing for the installation of 1.45M smart meters. $138M in SGIG funds ($301M total project value) was awarded to the utility to assist with this effort. 10,000 meters are planned for installation in 2010 with project completion by 2012. | PR-Inside[55]; T&D World[56] |
| **Oklahoma Gas & Electric** | OK, AR | 771,000 | OG&E plans to install 184,000 meters in 2010 with full deployment of a smart grid network to the entire service territory, including 771,000 meters and dynamic pricing options available by 2012. OGE has received approval from the Oklahoma Corporation Commission and was awarded $130M in SGIG funds ($366M total project cost). | smartmeters.com[57] |
| **Oncor** | TX | 3,400,000 | Originally a deployment of 600,000, Oncor's program expanded for all customers in north Texas; as of June 30, 2010 over 1,000,000 meters were installed; full deployment of 3.4M meters is expected by 2012. | Dallas Morning News[58];<br>Navigant Consulting[59] |
| **OUC** | FL | 20,000 | OUC, located in Orlando, FL, has about 20,000 meters on the Elster Energy Axis two way communication AMI system. | metering.com[60] |
| **Pacific Gas & Electric** | CA | 5,100,000 | As of June 2010 more than 3.1M electric smart meters have been installed throughout PG&E's service territory. A critical peak pricing (CPP) rate structure is in place for some customers along with a voluntary SmartRate program. The utility expects to reach full deployment by 2012. | PG&E Smart Meter executive summary[61] |
| **Pacific Northwest Smart Grid Demonstration Project** | ID, MT, OR, WA, WY | 60,000 | Avista*, NorthWestern Energy, Portland General Electric, and Seattle City Light represent the investor-owned and large public power utilities involved in a 5-year project that will provide two-way communication between distributed generation, storage, demand assets, and the existing grid.<br>*Avista's share of the project is listed separately. These 14,000 meters are not double-counted in our total. | Bonneville Power Authority[62] |
| **PECO Energy Company** | PA | 1,600,000 | PECO intends to upgrade its communications infrastructure to support a smart meter network with initial installation of 600,000 smart meters starting in early 2012. PECO intends to provide smart meters to 1.6M customers within the next 10 years, 5 years earlier than required by PA law. PECO received the maximum SGIG award of $200M to support their smart grid efforts. | PECO press release[63] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **PEPCO Holdings** | DC, DE, MD, NJ, VA | 1,900,000 | In January 2010, PEPCO received DC Commission approval to install smart meters in DC and received MD commission approval in August 2010. With intentions to fully deploy smart meters in its entire service territory by 2013, PEPCO is installing 280,000 meters in DC by the end of 2011 and 570,000 meters in MD. PEPCO received $168.1M in SGIG funds ($300M total combined value for two projects) to assist with their investments. | Washington Post[64]: Reuters[65]; Washington Informer[66]; PEPCO press release[67] |
| **Portland General Electric** | OR | 850,000 | PGE's smart meter program was approved by the commission in 2008; full deployment is expected to be completed by the fall of 2010. | PGE Earnings Report[68]; PGE Smart Meters web page[69] |
| **Progress Energy** | NC, SC, FL | 160,000 | Progress Energy is planning to deploy 160,000 smart meters, building off of the success of its EnergyWise program that provides energy savings to 400,000 residential customers through direct load control on certain appliances. Progress plans to begin installations in late 2010 or early 2011. Progress received a $200M SGIG award to assist with meter deployment and other customer-facing initiatives. | Progress Energy press release[70] |
| **PSE&G** | NJ | 17,500 | PSE&G received approval from NJ Board of Public Utilities to install 17,500 smart meters in three Passaic County towns. | PR Newswire[71] |
| **Puget Sound Energy** | WA | 700 | PSE is testing a demand response pilot program with 700 customers on Bainbridge Island | PSE press release[72] |
| **Sacramento Municipal Utility District** | CA | 620,000 | The utility board approved a 30-month rollout of the meters in June 2009. SMUD plans to install meters throughout their service territory along with dynamic pricing, 100 EV charging stations, and 50,000 demand response control devices. SMUD was awarded $127.5M in SGIG funds ($307.7M total project value) to support their efforts. | Sacramento Bee article[73]; DOE Recovery Act, Smart Grid[74] |
| **Salt River Project** | AZ | 935,000 | Salt River Project currently has approximately 400,000 meters installed and intends to add an additional 540,000 meters. Their next step is to provide a dynamic pricing structure to their customers. Salt River Project received $56.8M in SGIG funds (total program cost, $114M) to support the 540,000 smart meter investment. | SRP Smart Meter Page[75]; metering.com[76]; Phoenix Business Journal article[77] |
| **San Diego Gas & Electric** | CA | 1,400,000 | SDG&E's full scale smart meter deployment and infrastructure investment has been approved by the CA Commission. This $572M project will be complete in 2011. As of August 2010, SDG&E was installing 6,000 meters per day. SDG&E was awarded *$28.1M in SGIG funds ($60.1M total* project value) to develop the infrastructure to support the deployment of smart meters. | SDG&E Smart Meter website[78] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **Southern California Edison** | CA | 5,300,000 | Deployment began in June 2009, with full deployment expected by 2012 at a cost of $1.6B. As of August 2010, 1.2M meters were installed. Critical Peak Pricing (CPP) and Peak Time Rebate (PTR) rates are available to customers with enabling technologies. | SCE Presentation, IEE September 2010 meeting |
| **Southern Company** | AL, FL, GA, MS | 4,300,000 | Southern Company is moving forward with smart meter deployments throughout its service area. Georgia Power has deployed 1.3M meters out of a planned 2.5M; Alabama Power has deployed 1.2M of 1.45M and will complete their deployment in 2010; Gulf Power has deployed 13K of 420K meters. Southern Company is projected to reach full deployment by 2012-2013. Southern Company was awarded $165M in SGIG funds (total program cost, $330M) to upgrade necessary infrastructure. | GA Power smart meter page[79]; AL Power smart meter page[80]; Reuters press release[81]; Greentech Media article[82] |
| **State Program (Pennsylvania)** | PA | 6,000,000 | Act 129 (signed 10/15/2008) mandates that EDCs with >100,000 customers must provide smart meters either to customers that request one, for newly constructed buildings, or to all customers within fifteen years. Duquesne Light will offer 8,000 meters to customers by 2013. PPL expressed interest in a 60,000 unit pilot. Note: meters listed for Allegheny Power, FirstEnerg Corp, and PECO are not double counted in the total. | PA Act 12928[83]; smartmeters.com[84]; SNL[85]; Pittsburgh Tribune-Review[86] |
| **Tampa Electric** | FL | 10,000 | TECO is piloting a set of 250 smart meters in two of Tampa's most recently erected high-rise buildings. Plans to extend the pilot to 10,000 units to test remote connect/disconnect and DSM in 2010 or 2011. | metering.com[87] |
| **Tacoma Public Utilities** | WA | 17,000 | Tacoma Public Utilities currentlyhas 17,000 smart meters installed and were seeking asistance from the federal government for an additional 135,000 meters. | TPU press release[88] |
| **Texas New Mexico Power** | TX, NM | 231,000 | A trial of 10,000 meters was announced in early 2009; utility seeks to expand meters to entire service territory by 2013. The utility is employing SmartSynch's residential SmartMeter solution which uses standard IP communications via public wireless netrworks. | TNMP press release[89] |
| **Tucson Electric Power** | AZ | 100,000 | TEP has expanded advanced metering infrastructure and related support technologies to roughly 100,000 of their 400,000 customers. | Itron.com[90]; metering.com[91] |
| **Vermont utilities, Efficiency Vermont** | VT | 174,000 | VT Department of Public Service worked with VT's 20 utilities to extend smart grid technologies across the state. This program was launched prior to the SGIG funds awarded to VT Transco in October 2009. | Burlington Free Press article[92] |

| Utility | State | Target Number of Meters | Notes | Resources |
|---|---|---|---|---|
| **Westar Energy** | KS | 48,000 | Westar is piloting smart meters in its SmartStar project in Lawrence, KS. SmartStar is a customer-centric project and all customers will be offered a personal energy web portal accompanying the smart meter installation. The project includes other infrastructure required to support system-wide deployment of smart metering. The project is expected to take between 24 and 36 months to implement, with meter installations beginning Q2 2011. Westar was awarded $19M in SGIG funds (total project value, approx. $40M). | Marketwire.com article[93] |
| **Xcel Energy** | CO, MN, WI | 20,000 | Xcel is piloting a smart grid system known as SmartGridCity in Boulder, CO, testing peak pricing and in-home power monitoring and management technologies. Cost recovery is pending commission approval. | SmartGridCity, Xcel FAQ[94] |
| **Total** | | **64,839,650** | | |

This table illustrates planned and proposed deployments of smart meters across the United States in the next decade, including meter deployments funded through Smart Grid Investmetnt Grants awarded through the Department of Energy. If full deployment based on these initiatives is achieved, a total of 64,839,650 meters will be installed and operable by 2020. According to EIA's forecast of electricity customers in 2020, this represents roughly 50% of U.S. households.[95]

Note: The map shows the extent of smart meter deployments by electric utilities that are either completed, underway, or planned with a completion date of 2020 or before. For the purposes of this reference, smart meters are defined as advanced meters that allow for two-way communication and real-time electricity consumption information. This map does not include automatic meter reading (AMR) installations. Information was compiled using the latest public data available as of September 1, 2010. Readers are encouraged to verify the most recent developments by contacting the appropriate utility or regualtor.

**For inquiries or to provide feedback, please contact Adam Cooper at acooper@edisonfoundation.net. For further information, please visit http://www.edisonfoundation.net/IEE/.**

*References:*

1. *AEP also has service territories in AR, TN, and LA but have not been included in the map due to the small number of customers they represent in terms of the total number of end-users in those states. AEP customers in these service territories will also receive smart meters under the utility's plan.*
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# APPENDIX E: NRECA SMART GRID MAP

National Rural Electric Cooperative Association

Help

Enter search item or keyword SEARCH

Home About Us About Our Members Our Programs Our Issues News Room

- **Co-op Facts & Figures**
- **History of Electric Co-ops**
- **Maps**
  - Cooperatives and Renewable Energy
  - Cooperatives Promote Efficiency
  - Cooperatives and the Smart Grid
  - Cooperative Service Territory
  - Generation and Transmission Cooperative Service Territory
- **Electricity 101**
- **Tax-exempt Status**
- **Member Directory**
- **Network with Co-ops**

Home > About Our Members > Maps > **Cooperatives and the Smart Grid**

# Cooperatives and the Smart Grid

(Data updated February 2011.)

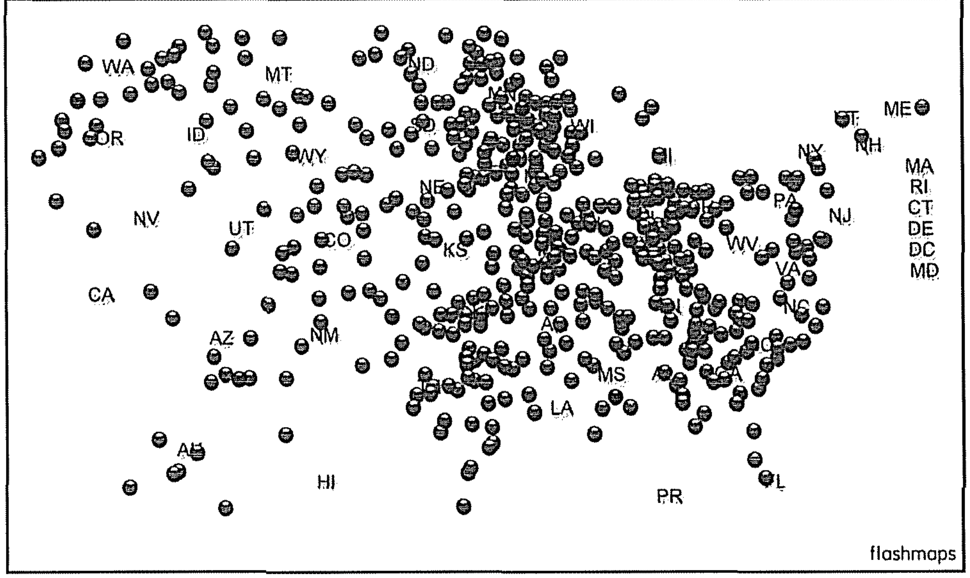
Across the nation, rural electric cooperatives are deploying advanced communication and automation technologies to improve services, increase reliability and help to control electricity costs for members. As the Federal Energy Regulatory Commission (FERC) found in its 2008 survey, co-ops lead the industry in the penetration of advanced meter infrastructure (AMI).

Summary information and national totals are listed below the map on this page.

● Distribution Cooperative
● Generation & Transmission Cooperative

(Click dots on the map below for co-op specific details.)

**View:** Cooperatives and smart grid deployment **Zoom To State:** Full U.S. Map View Initial View

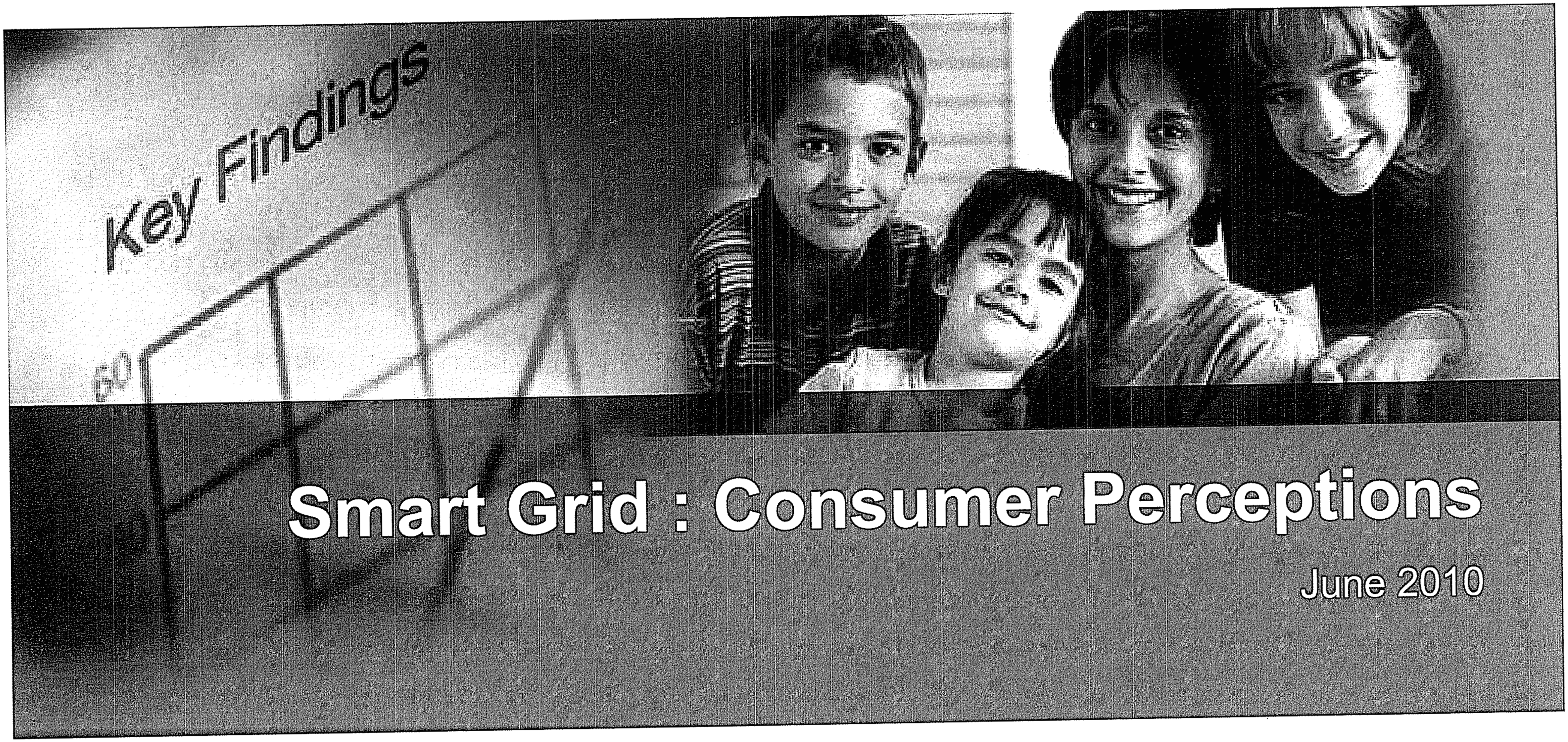


- According to a 2011 Federal Energy Regulatory Commission report, cooperatives continue to show the largest penetration of Advanced Metering Infrastructure: 25 percent, compared to 8.7 percent for the country as a whole.
- More than 50 co-ops and public power districts in 15 states are receiving $215.6 million in smart grid investment grants from the Department of Energy
- 27 cooperatives in 12 states are participating in the Cooperative Research Network's Smart Grid Demonstration Grant, supported by a $34 million matching grant from the U.S. Department of Energy
- Approximately half of cooperatives have installed AMI/AMR infrastructure on part or all their system (National Rural Electric Cooperative Association Market Research)
- 30 percent of cooperatives with AMI/AMR have begun to integrate their metering systems with other systems such as outage management systems, customer information systems and geographic information systems (NRECA Market Research)

Contact information for individual cooperatives and statewide associations can be found by using the member directory .

# APPENDIX F: NRECA SMART GRID: CONSUMER PERCEPTIONS

NRECA
MARKET
RESEARCH
SERVICES



Key Findings

# Smart Grid : Consumer Perceptions

June 2010

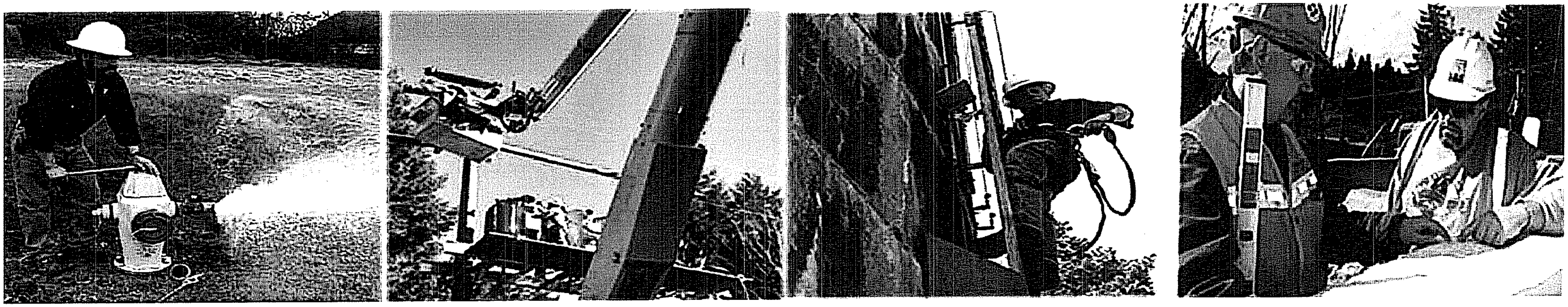
NRECA
A Touchstone Energy® Cooperative

# Peninsula Light Co.

*a mutual corporation · since 1925*

*The power to be...*

## Jonathan White
## Director of Member Services and Marketing



*the power to be...*

Peninsula Light Co.

# Who We Are

- Founded in 1925
- Located in Gig Harbor, WA
- 31,000 meters
- Full requirement utility of BPA (100% of power from Feds)
- Second largest cooperative in Washington

# Who We Are

- Retirement Community
- Own home
- College educated
- Computer literate (85% have a access to a computer)
- 23% pay bills online
- Majority have lived in community for 20 years >
- 2 member household
- More satisfied
- Most critical

# Power Resources

## BPA

BONNEVILLE
POWER ADMINISTRATION

- Federal agency under the U.S. Department of Energy
- Serves Pacific Northwest
- Provides wholesale electrical power at preferred cost from mostly hydro
- 'Business as Usual' with BPA ends 2010

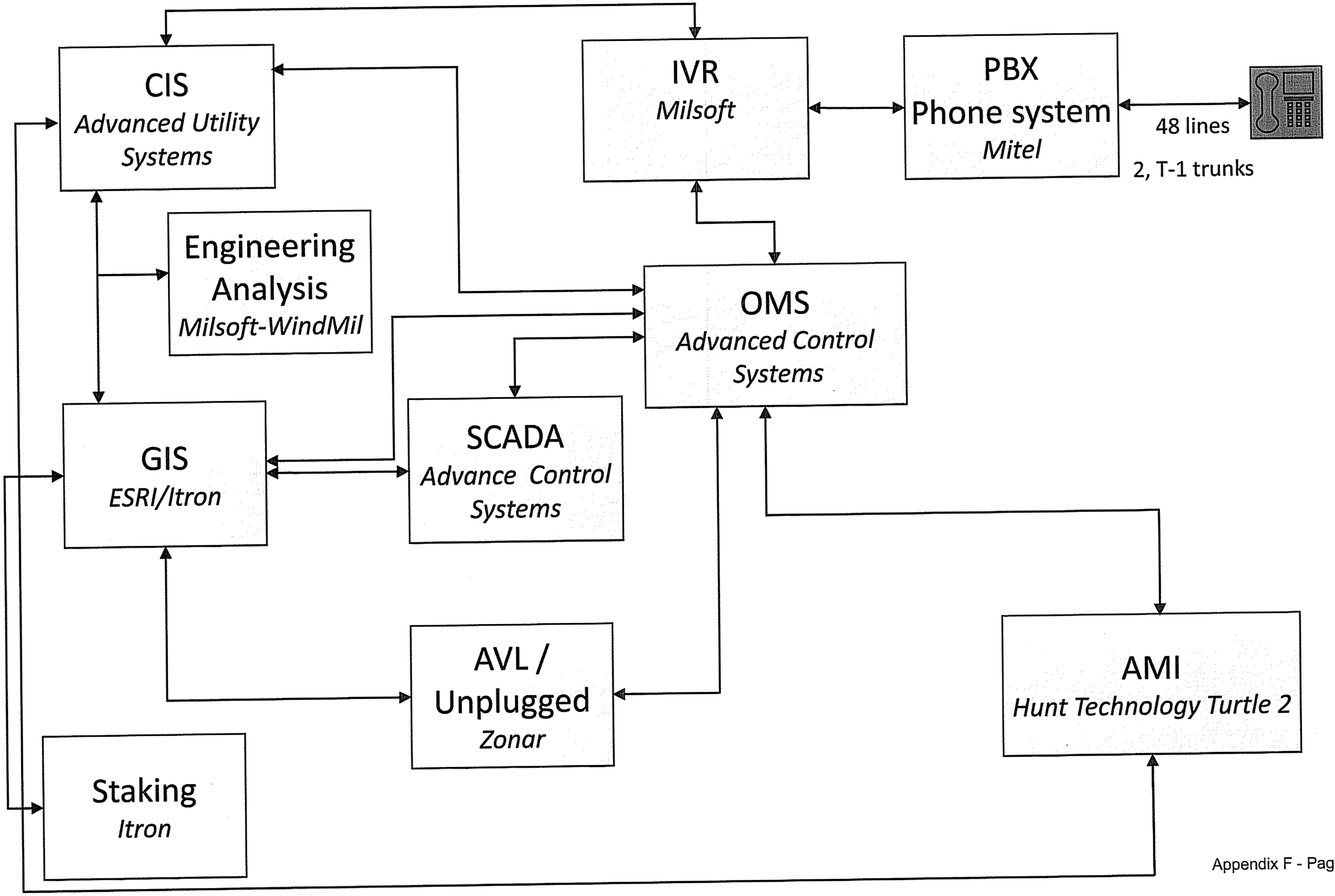
# BPA Rate Adjustment

## October 1, 2011: (FY2012 – FY2013 Rate Period)

### Three Things are Going to Happen…

1. BPA Tiered Rates Contract Takes Affect
2. Significant Change to BPA Rate Design
3. Rate Increase from BPA

# PenLight Technology Interfaces



**CIS**
*Advanced Utility Systems*

**IVR**
*Milsoft*

**PBX**
**Phone system**
*Mitel*

48 lines

2, T-1 trunks

**Engineering Analysis**
*Milsoft-WindMil*

**OMS**
*Advanced Control Systems*

**GIS**
*ESRI/Itron*

**SCADA**
*Advance Control Systems*

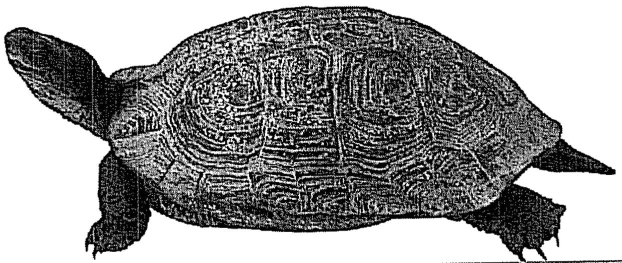
**AVL / Unplugged**
*Zonar*

**AMI**
*Hunt Technology Turtle 2*

**Staking**
*Itron*

# Cellnet Technologies + Hunt

- Deployed in 2006
- Turtle 2 technology – 2 way Communication Power Line Carrier
- Ultra-narrow-bandwidth (UNB)
- Reading every 24 hrs
- Status every 20 minutes - OMS
- No real-time reading



# SMART GRID For PenLight

- Automated Meter Reading
- Faster Outage Response
- Smart Switching (Component of Reliability)
- Accurate Utility Data
- Conservation Voltage Reduction
- Small Scale Demand Side Management (DSM)
- Peak Load Shifting
- Small Scale Conservation

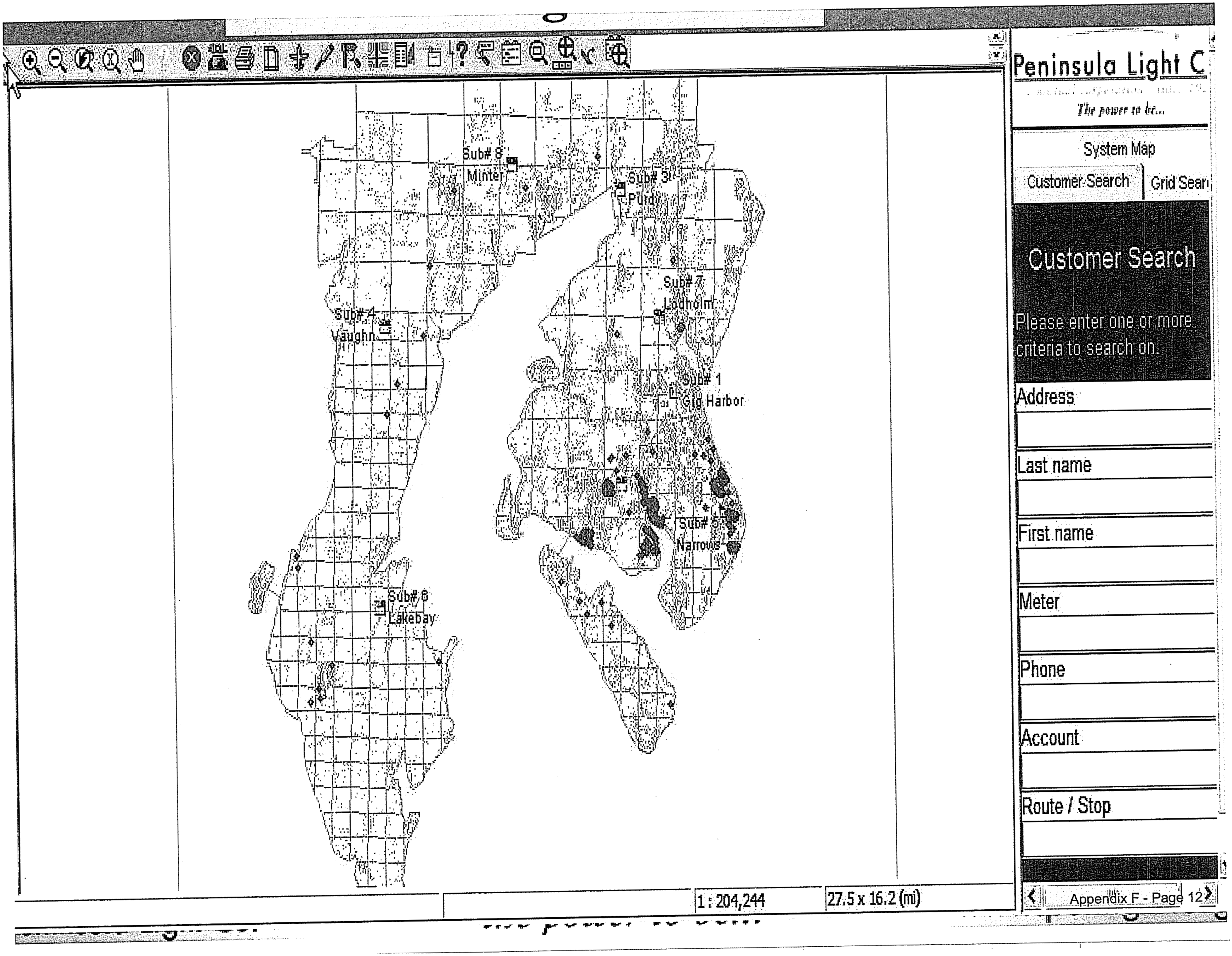
# SMART GRID For PenLight Members

- Automated Meter Reading
- Faster Outage Response
- The ability to monitor daily energy consumption
- Real-time energy usage with Zigbee technology
- The ability to participate is Demand Side Management (DSM) projects

# SMART GRID

## What Does PLC do with its Smart Grid Capabilities?

- AMI
- Automated Meter Reads
- Mining Better Utility Data
- Meter Status Integrated with GIS
- Smart Switching Pilot Project
- Demand Side Management (DSM)
- Load Control Device Pilot Project



Customer Search

Please enter one or more criteria to search on.

Address

Last name

First name

Meter

Phone

Account

Route / Stop

# Objectives

- Residential consumers' perspectives on current energy situation
- Steps consumers taking to save on electricity costs
- Familiarity with, reaction to Smart Grid concept
- Reaction to various forms of in home displays high lighting energy usage

# Methodology

- **Series of 90 in depth interviews conducted to date**
  - Conducted, one-on-one, in person at 7 co-ops nationwide
    - ✓ Co-ops in AZ, GA, OR, WA, MN
    - ✓ Sample included co-ops relying on coal-fired, gas-fired, and hydro power
  - Each interview lasted approximately 45 minutes
  - Most held onsite at co-op office
- **Recruited 15 member participants at each co-op**
  - One third retired
  - One third empty nesters still employed
  - One third working with children at home

# Research Findings

# Assessment of Energy Situation

- **Vast majority feel energy situation will be a major challenge in next few years**
  - Limited energy resources compounded by waste by Americans, and inability to influence other countries' usage patterns
  - Need for energy independence
  - Pollution concerns
    - ✓ Acquiring
    - ✓ Burning
    - ✓ Disposal of nuclear waste
    - ✓ Fish habitat issues
  - Minority point to climate change and use of fossil fuels as key energy concern
    - ✓ However, strongly held convictions about climate change
  - Majority feel electricity rates will increase in future, but no faster than rate of inflation

[redacted]

[redacted]

# Understanding of How Their Power Is Generated

- Few are aware of how their electricity is generated
- In Pacific Northwest, many aware their power generated by hydro
- Most do not associate their electricity with burning of fossil fuels
- Those more environmentally focused, more concerned about climate change, are more likely to know how their power is produced

# Household Efforts to Minimize Electricity Use/Bill

## What are they doing now or have they done recently?

- Turn off lights when leave rooms
- Only do full loads in washer and dishwasher
- Line dry clothes rather than tumble dry
- Turned up/down thermostat to use less power
- Some have looked to reduce vampire loads
- Replace many bulbs with CFLs or LEDs
- Most have made steps to make house more energy efficient
  - Insulation
  - Windows
  - Weather stripping
- Many have sought out energy efficient appliances when replacing those that fail or when upgrading kitchen
- A minority have programmable thermostats
- Very few have replaced heating/cooling systems with more energy efficient models

[redacted]

[redacted]

# Familiarity with/ Reaction to Smart Grid Concept

- Almost universally, no familiarity with term Smart Grid
- Those who heard term couldn't accurately define it
  - A few feel it refers to improving/upgrading current

# Reaction to Smart Grid Concept

## ❖ Description

### *Smart Grid*

- Integration of two way communication into electric power grid (driven largely by AMI)
- closer to real time information about usage and power quality
  - Quicker response to outages,
  - more efficient distribution of power,
  - more consistent voltage,
  - improved predictive maintenance preventing problems before they occur,
  - load control,
  - providing consumers more usage information they can act on (in home displays), and
  - allowing integration of distributed generation into grid.

# Reaction to Smart Grid Concept

- Some indicated their co-op had recently installed AMI in lieu of using meter readers

- Most responded positively
  - Seen as improving utilities' efficiency and service quality
  - Helping utility stretch their power supply further
  - Assisting consumers in saving money

- A few expressed concern
  - "Big brotheresque" sharing/mining of personal information
  - Expense of investing in Smart Grid technology
  - Concern that Smart Grid technology will malfunction
  - Data security and increased vulnerability to terrorist attacks

[redacted]

# In Home Display: Model 1

**Device Features:**

- ❖Track electricity usage and associated costs incorporating rate signals from power company
- ❖Gauge power usage of individual appliances in house

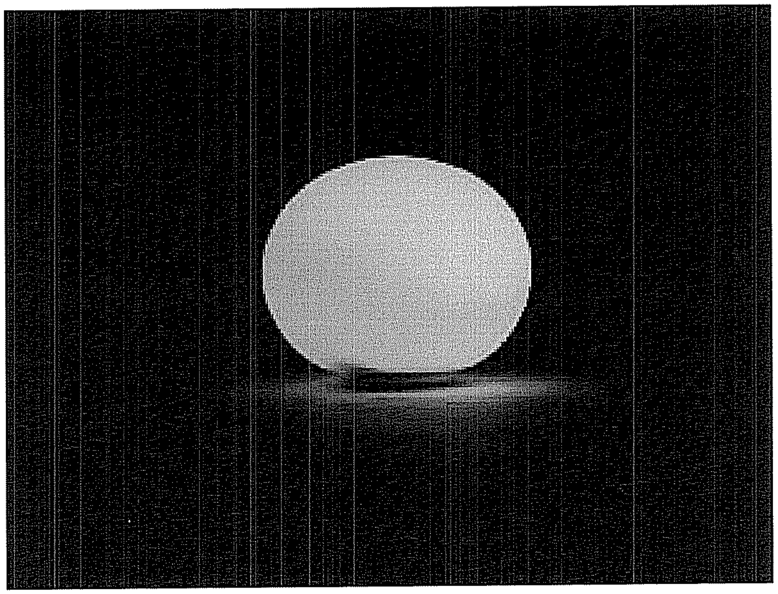
**BLUE LINE INNOVATIONS POWERCOST MONITOR (BATTERY OPERATED)**

# In Home Display: Model 2

## Device Features

- Attractive design, intended to be prominently displayed in living area
- Glows different colors to reflect current demand and rate for electricity
  - Green means normal rates apply
  - Red means peak pricing

**AMBIENT DEVICES ENERGY ORB (PLUG IN)**

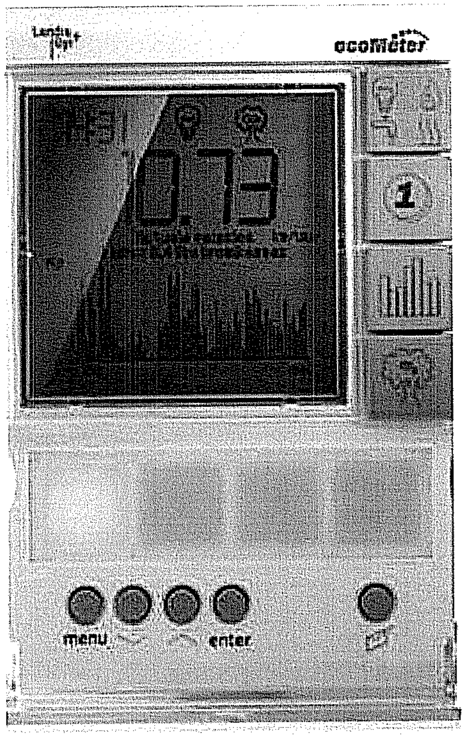


# In Home Display: Model 3

**Device Features:**

- ❖Tracks electricity usage in kWh and dollars
- ❖Bar charts showing daily, weekly, monthly, annual usage
- ❖Can do same for natural gas and water
- ❖Traffic signal for increased demand/rate periods
- ❖Alerts from power company
- ❖Estimates carbon footprint from electricity usage (CO2 produced)

**LANDIS+GYR'S ECOMETER (PLUG IN)**



# In Home Display: Model 4

**Device Features:**

- Tracks electricity usage in kWh and dollars
- Shows hourly usage for past day and daily usage for past month
- Lighted arc at top of device moves at speed corresponding to amount of electricity being consumed
- Traffic signal for increased demand/rate periods
- Alerts from power company

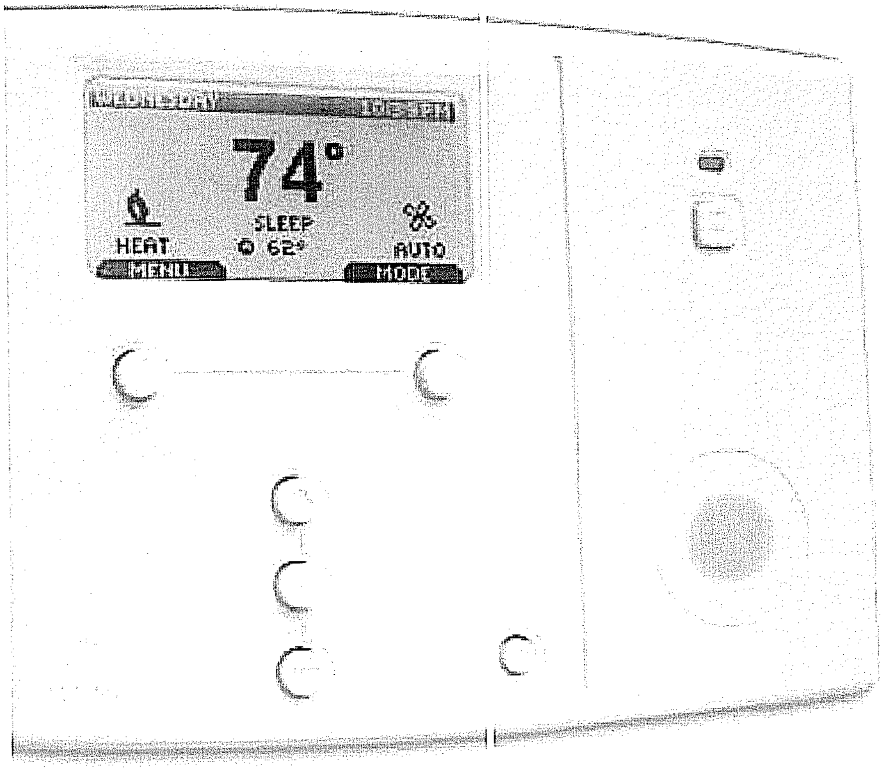
**AzTech In Home Display (Plug-in or Battery)**

# In Home Display: Model 5

**Device Features:**

- Programmable thermostat whose settings can be programmed to adjust based upon demand driven pricing signals from power company
- Can be adjusted remotely over Internet
- Traffic signal reflecting demand driven rates
- Has manual override

**TANTALUS ST-1480**
**(SMART THERMOSTAT AND IHD COMBINATION)**



# Google PowerMeter: Model 6

**Data Features:**

- ❖Tracks energy usage
- ❖Predict annual bill
- ❖Shows portion of total usage attributable to devices 24 x 7
- ❖Budget tracker – set energy savings goal and track progress
- ❖Discussion board with other consumers to share energy savings tips

## GOOGLE POWERMETER

**Track energy over time**

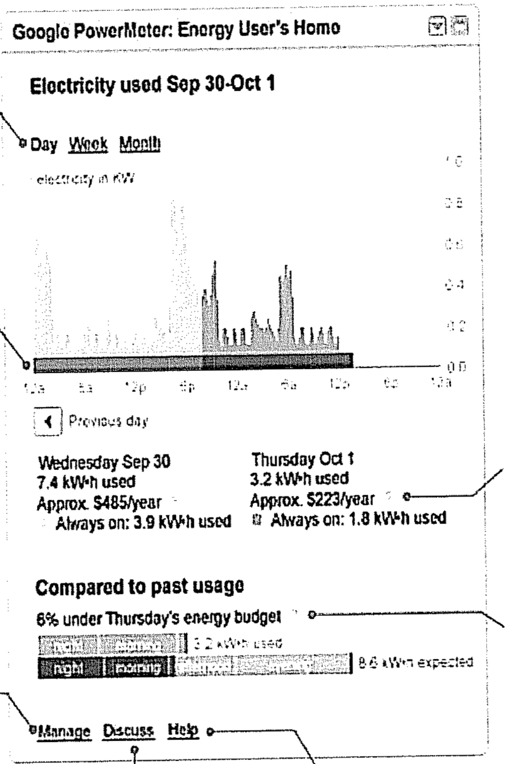
See how much energy you have used by the day, week or month.

**Always on power**

The darker shaded portion of the graph shows power that is always on, such as any appliance that goes on standby mode. Many appliances are always on; you just don't know it. Discovering these is one of the easiest and fastest ways to reduce energy use and save money.

**Customize your experience**

Add your estimated cost per kWh, sign up for weekly emails, and share your usage with family and friends.



**Google PowerMeter: Energy User's Home**

**Electricity used Sep 30-Oct 1**

Wednesday Sep 30
7.4 kW·h used
Approx. $485/year
Always on: 3.9 kW·h used

Thursday Oct 1
3.2 kW·h used
Approx. $223/year
Always on: 1.8 kW·h used

**Compared to past usage**

6% under Thursday's energy budget

3.2 kWh used

8.6 kWh expected

**Predict your costs**

Google PowerMeter helps you to predict your annual energy bill so that you can start making change and saving early.

**Budget Tracker**

Set an energy savings goal for yourself and track your progress.

**Join the community**

Get tips on how to save from other Google PowerMeter users and share what has worked for you.

**Have a question?**

Learn more about Google PowerMeter from our online help center.

[redacted]

[redacted]

# Factors Influencing Consideration of In Home Displays

- Degree to which power bill is significant portion of budget

- Extent see power costs rising in future

- <u>Mindset</u>
  - *Green*
  - *Frugal*
  - *Frenzied/Busy*
  - *Analytical*
  - *Gadget-phobes*

# Factors Influencing Consideration of In Home Displays

- **Self assessment of own efforts at minimizing power usage/bills**
  - How much room for improvement/further savings

- Number of people in residence

- Retirees less interested than might have expected

- Current price points of devices prohibitive for many, unless

# Factors Influencing Choice of In Home Displays

- Amount of time spent at home
  - Retirees, homemakers, and those running businesses from home generally preferred models which told them when peak periods were occurring (many like Orb – easy to use, understand)
  - Those who spend more time out of home
    - Like "set it and forget it" aspect of Smart Thermostats
    - Also like ability to adjust remotely over internet
- Presence of pets in home
  - Wouldn't sign up for load control or Smart Thermostats due to concern about pets' health
- Analytical
  - Like Google PowerMeter and others providing usage information
  - Like detail available on usage patterns
  - See Orb as overly simple
- Tech Savvy
  - More interested in Smart Thermostats
    - Like their automated nature
    - Comfortable with setting
- Level of privacy concerns
  - Discomfort having personal usage information available

# Questions???

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# APPENDIX G: JOINT PARTICIPANT COLLABORATION

## PSC CASE NO. 2008-00408 MEETING/CONFERENCE CALL PARTICIPANTS

| | 11/18/10 | 2/4/11 | 2/18/11 | 3/3/11 | 3/18/11 |
|---|---|---|---|---|---|
| American Electric Power-Kentucky | X | X | X | X | X |
| Atmos Energy | | | | | |
| Attorney General's Office | | X | | X | X |
| Bates & Skidmore | | | | X | X |
| Big Sandy RECC | | | | X | |
| Bluegrass Energy Coop | | | | X | X |
| Big Rivers Electric Coop | X | X | X | X | X |
| Community Action Council | | | | X | X |
| Clark Energy Coop | | X | | | X |
| Columbia Gas | | X | X | X | |
| Cumberland Valley | | | | X | X |
| Delta Natural Gas | | X | | X | |
| Duke Energy | X | X | X | X | |
| East Kentucky Power | X | X | X | X | X |
| Farmers RECC | | | X | X | |
| Fleming Mason Electric Coop | | X | | | |
| Frost Brown Todd | | | | | |
| Grayson RECC | | | | | |
| Intercounty Energy | | X | X | X | X |
| Jackson Energy | X | X | X | X | X |
| Jackson Purchase Energy Corp | X | X | X | X | X |
| Kenergy Corp | | X | X | X | X |
| KIUC | | | | | |
| LG&E / KU | X | X | X | X | X |
| Licking Valley RECC | | | | | |
| Meade County RECC | | X | | X | X |
| Nolin RECC | | | | X | |
| Owen Electric | | X | X | X | |
| P.D. Engineers | | | | | |
| Rhoads & Sinon | | | | | |
| Salt River Electric | | | | | |
| Shelby Energy Coop | | | X | | |
| South Kentucky RECC | | X | | | |
| Stites | X | | | X | |
| Sullivan Mountjoy Stainback Miller | X | | | X | |
| Taylor County RECC | | | | | |
| Trilliant | | | | | |