Collaborative Two-Part AMI Programs for Demand Response and Energy Efficiency

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ABSTRACT

Utilities around the country are implementing Advanced Metering Infrastructure (AMI) programs to reduce operating expenses, improve service reliability and support Demand Response (DR) and Energy Efficiency (EE) programs. Evaluation of AMI initiatives based only on demand response (DR) and energy efficiency (EE) benefits represents only part of the picture. AMI initiatives support reliability and produce significant Operating and Maintenance (O&M) savings, especially when coordinated with Distributed Automation (DA). The cross benefits challenge regulatory entities including state commissions and consumer advocates to analyze AMI effectiveness since all benefits must be weighed against costs. So what are regulators to do when evaluating an AMI program "wish list"? Often, utilities present regulators with a long list of technological components and highlight the DR/EE benefits more aggressively than system reliability and O&M benefits which are more difficult to quantify, monitor and verify.

This paper proposes a two-part AMI program, combining the reliability, O&M and DR/EE benefits from customer response with the automated distribution benefits gained from improved utility operations. A multi-phase technology assessment which includes system plans and highlights all potential benefits can form the foundation for AMI evaluation prior to program implementation. Pilot studies followed by full-scale AMI deployment may drive effective decision making. From a regulatory perspective, challenges include cost containment, benefit maximization and reasonable cost recovery to increase consumers' access to DR/EE programs. The paper also proposes a strategy of utility driven DR/EE collaboratives to develop a two-part AMI program from a consumer advocate perspective with circulation of success stories.

Introduction

Electricity demand in the United States is expected to increase dramatically to satisfy growing consumption in the short- and long-term. The Energy Information Administration projects a 39 percent increase in residential electricity demand from 2005 to 2030, with total electricity sales increasing 41 percent, from 3,660 to 5,168 billion kWh, in the same time period (EIA 2007). Another dimension of industry challenges is inevitable increases in customer prices due to increasing fuel and capacity costs and impending Federal environmental regulations. While Indiana consumers enjoy some of the lowest electricity rates in the US, they are not isolated from rising fuel and electricity costs nationwide. The SUFG forecasts a 4.4% compound growth in residential electricity prices from 2005-2010 (SUFG 2007, 5-9).

From a consumer advocate perspective, utilities must provide reliable service at least-cost, reasonable prices. There is an increasing consensus among energy stakeholders that an integrated approach, combining supply-side and demand-side solutions, is the best way to achieve this goal. In a February 14, 2008 Federal Energy Regulatory Commission (FERC) press release on convening a "Smart Grid" dialogue, FERC Chairman Joseph T. Kelliher is quoted, "meeting our future energy needs requires new generation and transmission capacity, demand response and conservation and efficiency" (FERC 2008, 1).

This environment of increasing system demand, rising prices and interest in reliable service presents a dilemma, which cannot be solved with a 'silver bullet.' A part of the solution with both economic and reliability benefits is Advanced Metering Infrastructure (AMI).

This paper proposes a two-part AMI program, combining the reliability, O&M and DR/EE benefits from customer response with the automated distribution benefits gained from improved utility operations. The paper will discuss the economic and reliability benefits as rationale for AMI deployment, cost barriers to deployment and the new, two-part approach to AMI programs. The paper also includes examples of successful collaborative AMI programs in Indiana.

Defining AMI

The term "AMI" is broadly defined, generally referring to metering technology which measures, collects and analyzes energy use through various communication medias. The most important aspect of AMI is that it enables two-way communication between the utility and customer. Because of this two-way communication, AMI has potential applications in pricing options, demand response, customer feedback, customer bill savings, and outage management and distribution operations. This stands in contrast to more traditional Automated Meter Reading (AMR) using one-way communication. Because of the broad nature of AMI applications, the range of benefits and costs of a full AMI system appears endless. To manage, understand, and choose among these "endless possibilities," a collaborative approach to AMI deployment is vital, as it engenders project objectives and expectations. The economic and reliability benefits of AMI will be further discussed later.

Barriers to AMI Deployment

There are six significant barriers to AMI deployment. The first barrier is practical resource allocation by the utility, primarily due to the time and expertise required to develop and deploy AMI systems. The process is complicated and takes coordination among many areas of the utility, including Information Technology (IT), billing, customer services, field operations and engineering. A second barrier is the cost of AMI systems. These costs increase dramatically because two-way communication may require back office integration of software systems such as customer billing systems and SCADA. For many utilities, these back-office programs are proprietary and stand-alone. A third barrier is the rapid change in technologies. What appears to be a prudent investment in one technology today may not be prudent tomorrow.

The fourth barrier to AMI deployment is a concern of the risk of stranded assets. This is partly due to rapid changes in technology and the risk that customers may not respond to demand response offerings which may drive cost savings. A fifth barrier focuses on regulatory risks, in particular the focus on cost recovery. Furthermore, different infrastructure costs may deter utilities from investing, especially if payback periods exceed expected time between rate proceedings for traditional regulated utilities. The sixth significant barrier is tracking costs and benefits. Because of the wide array of benefits and costs presented in each set of AMI system options and applications, accounting for each cost and benefit is complicated.

Developing a business case including accurate payback periods is complex based upon multiple dynamic inputs. The costs of an AMI project depend on project design and more importantly project objectives. McKinsey and Company developed an example project valuation model ("The McKinsey Model") in 2006 to "assist utilities, public utility commissions (PUCs), regulatory agencies, vendors, and customer advocacy groups in conducting a preliminary value assessment for the installation of an Advanced Meter Infrastructure system by providing an illustrative example model" (McKinsey and Co. 2006, 3). The McKinsey model includes cost analysis in its scope, and lists three key areas of capital expenditure for AMI: Meters, Network, and Installation, and O&M savings associated with any AMI project.[1]

The cost of meters can vary greatly, generally in the range of $100-400 per meter depending upon complexity of voltages (single phase versus three phase).[2] A ConEdison "Plan for Development and Deployment of Advanced Electric and Gas Metering Infrastructure" lists metering equipment as the single most significant cost factor, accounting for approximately 53% of total costs in their plan (ConEdison 2007). There is a strong argument to be made of economies of scale, that the incremental cost of AMI meters will be reduced in the long run. This will occur as a result of advanced AMI technology, greater AMI prevalence, and advances in complementary technologies and industries. A reduced per meter cost will only increase the net benefits associated with AMI.

Network costs can range as greatly as the meter cost. These costs include capital expenditure for a Local Area Network (LAN), Wide Area Network (WAN), or WiMax (Worldwide Interoperability for Microwave Access) communications network infrastructure, software costs and data management systems. A DA network also includes software and communications infrastructure costs. Returning to the ConEdison plan, which only includes AMI network costs, the costs associated with an AMI network account for approximately 8% of total costs (ConEdison 2007). It would be expected that inclusion of distribution automation would increase that percentage.

Installation costs are dependent on the AMI system type and can be more expensive for commercial meters than residential meters. A Radio Frequency (RF) Mesh data collector system incurs different costs than a high-power (e.g. WiMax) system. As with network costs, the cost of installing distribution automation can significantly increase the total installation cost. The ConEdison plan allocated 12% of total costs to meter and data collector installation.

O&M and labor costs constitute the remainder of total AMI costs. The costs together should account for approximately one-fourth of total costs. O&M costs generally include monthly communication fees, software maintenance, meter maintenance and testing, and increase with the expected life of the program. Labor costs include costs to support the AMI system and perform O&M functions listed above, as well as include labor for programming and rate design.

A Collaborative Approach

Electric utility stakeholders in Indiana are working together to overcome barriers and to implement full AMI systems with complimentary DA applications. Initial discussions were initiated as part of the required state level analysis of the Energy Policy Act of 2005, and

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[1] For the purposes of this discussion, focused on AMI pilot programs, we will consider capital expenditures to be the greatest cost incurred, due to the short program life.

[2] See Faruqui, A., 2007, "The Power of Five Percent" that estimates a cost of $100-200 per meter exclusive installation cost. Recent discussions with industry staff indicate larger expenditures, however, specific contracts are not publicly available.

culminated in settlement discussions for two specific cases. The Office of Utility Consumer Counselor (OUCC) and two investor-owned utilities are working to implement technologies to improve service reliability, minimize operating expenses and facilitate demand response. The parties agreed not to implement technology for the sake of technology, but rather define objectives and means to accomplish them through AMI. Establishing clear project objectives minimizes scope creep and maximizes capital investment dollars, while directing benefits and costs most critical to a specific utility.

Indiana Michigan Power Company (I&M), a subsidiary company of American Electric Power (AEP), began a collaborative effort with the Indiana Office of Utility Consumer Counselor (OUCC) to develop smart metering and distribution automation. The program, titled the "Smart Meter and Distribution Automation Pilot Program (SMPP), is a $7 million program aimed at 10,000 customers. The pilot will explore actual system deployment feasibility and costs and potential benefits, including time-of-use rates, direct load control, remote connect/disconnect and pre-pay metering. Monthly collaborative meetings between I&M and the OUCC have been successful in defining pilot objectives, identifying hardware, software and data requirements and discussing tariff requirements. The collaborative also visited AEP's Dolan Lab to see first-hand an AMI testing environment. The SMPP will complete its technology assessment following vendor selections, the establishment of project tracking mechanisms and equipment ordering, by the end of second-quarter 2008, with mass deployment of the pilot phase planned by the end-of-year 2008.

In a similar fashion to I&M, the Vectren AMI study and pilot is a collaborative effort with the OUCC, intended to improve customer service/satisfaction, improve operational cost, manage future energy demand and coordinate with the regulatory investigation of AMI capabilities. The Vectren AMI project tracks closely to the two-part program proposed in Figure 1. Vectren will complete its study of a business case with cost/benefit analysis and a demand response assessment near the end of 2008. A full AMI system will not be implemented until 2010, at the earliest.

Benefits of AMI Deployment

Generally speaking, there are both economic and reliability benefits associated with AMI. An important source of economic benefits is achieved through reduced O&M expenses. Automated meter reading, a primary benefit of AMI, will likely reduce on-going meter reading labor and overhead expenses for all customers. Other O&M benefits accrue through automatic outage prediction and verification and the ability to use data to predict circuit trouble spots and avoid outages. These benefits are harder to model and account for than pricing benefits, and are separate from demand reductions. They are, however, beneficial for both customer and utility. The McKinsey Model contains an O&M benefits portion which captures, among other things, data backhaul and software maintenance costs. It also accounts for reductions or changes in utility staffing.

Another source of economic benefits associated with AMI is the enabling of time based rate designs. There is much truth in the saying that "smart meters are not effective with dumb rates." From another perspective, dynamic pricing can only work if price signals are accurately and effectively communicated to customers.

Dynamic pricing operates on market-driven concepts that promote economic efficiency. It may take the form of real-time pricing (RTP) rates, time-of-use (TOU) rates, or critical peak pricing (CPP) rates. All three differ greatly from traditional electricity rates because they take into account the times when electricity demand peaks. Electricity produced during seasonal peaks costs more due to higher cost fuel sources (such as oil or gas) than baseload (coal or nuclear). A traditional electricity rate is based on embedded historical costs, expressed as fixed price and variable components, operation and maintenance (O&M) costs, energy delivery costs, and others, which are averaged throughout a billing period.

Many case studies and pilot programs have been initiated.[3] They vary in number of customers, customer classes, rate designs, and other factors that affect their statistical results. One pilot program which yielded demand reductions among different rate options was the California Statewide Pricing Pilot (CA SPP). California's major power crisis in 2000 and 2001 resulted from a multitude of problems, not the least of which was a lack of dynamic price signals in retail markets. In the wake of this market failure, California's three Investor Owned Utilities (IOUs) and regulators developed a pilot "to help address the uncertainty regarding customer load impacts" (Faruqui & George 2005, 53). One important conclusion was that reductions in peak loads varied greatly for each rate option, including time of use, and Critical Peak Pricing (CPP) with fixed and variable options. The most successful reduction occurred with the variable CPP rate option.

The Brattle Group published a discussion paper on May 16, 2007 titled, *The Power of Five Percent*. The authors assume a five percent reduction in peak pricing from dynamic pricing. This assumption is based on probabilistic simulations of technical and economic potentials of dynamic pricing. When this "five percent theory" is applied to avoided capacity costs, transmission and distribution needs, and avoided energy costs; a five percent demand response reduction is worth $35 billion over 20 years nationwide. This is an astonishing number; yet, based on research presented in this paper, a five percent consumption reduction is realistic.

The reliability benefits of AMI center on distribution service improvements. Meter signals may be integrated to Outage Management Systems (OMS) through the communications network of AMI. When service is interrupted, the loss of voltage automatically sends a signal to improve outage prediction accuracy and decrease outage durations. These same meter signals may be tied to automated Interactive Voice Response (IVR) systems to communicate expected outage duration with customers to improve customer satisfaction and decrease customer contact expenses. Once an outage is restored, the OMS may be used to automatically "ping" meters to verify restored service and utilize exception reporting routines to create a new outage ticket for those customers still out. (This may occur if a single transformer is out of service after a line segment is placed back in service).

The two-way communication infrastructure backbone established for AMI may be utilized by utilities to control devices on their distribution systems such as reclosers or airbreak switches located either within or between substations to significantly increase reliability. This practice, known as Distributed Automation (DA), may be used in conjunction with Supervisory Control and Data Acquisition (SCADA) or Energy Management Systems (EMS) to reduce outages through automated or remote restoration routines. Labor and expense savings from reduced trips to verify field conditions or manually isolate areas where equipment is affected by an electrical fault serve as an off-set to system deployment costs.

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[3] Some of the most well-known dynamic pricing programs are the Illinois Energy Smart Pricing Plan (ESPP) (active from 2003-2005) and its continuation in the Ameren Power Smart Pricing program, Georgia Power, Gulf Power's GoodCents, Niagara Mohawk, and the Salt River Project TOU rate.

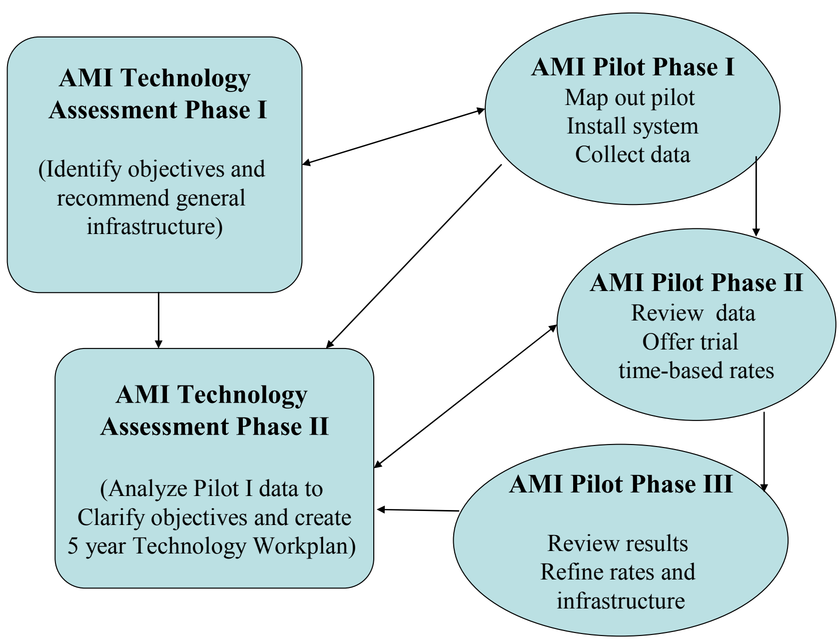
When system protective devices or switches are equipped with modules to enable remote access, dispatchers may open or close devices to restore electricity service following an interruption to the most customers possible. The effects of incidents such as animal exposure, equipment failure, weather damage, or public accidents are greatly reduced in this manner. If additional “intelligence” is built into devices, the reconfiguration of circuit flow may occur automatically based on specific system design parameters. Technologies which enable this type of system “self-healing” are often referred to as “smart”. They may include recloser controls, relays, capacitor banks, and switches.

Other indirect benefits of AMI include utilizing accurate customer-specific load data to assess the actual loading of distribution facilities including transformers and protective devices within modeling software to maximize efficiencies. Potential overload conditions which will likely decrease the useful life of assets or cause service interruptions may be avoided. In addition, utility staff may use to improve long-term load forecasting and long-term system planning with accurate usage information. Allocation of costs and tailored rate design by customer class may result when supported by specific usage data.

A New Approach: Two-Part AMI Programs

Figure 1 proposes an AMI program flow enveloping typical AMI pilot structure and the additional items to address AMI technology.

Figure 1. AMI Project Flow-Chart



The objectives for the AMI program are assessed in two phases, AMI Technology Assessment Phases I and II, which form the foundation for the phased pilot implementation, AMI Pilot Phases I and II. AMI Technology Assessment Phase I establishes the expected outcomes of the AMI project and includes a prioritization to direct research and project development. Broad measures of costs and benefits and ideally includes multiple technology options are considered to yield an optimal recommendation. Furthermore, including the O&M, EE, and DR effects during the first assessment phase captures all potential sources of economic and reliability benefits and costs. During this phase stakeholders discuss system goals, such as implementing intelligent schema and remote access to recloser units, and assess what is needed to accomplish this goal, such as identifying communication backbone, hardware, software and communication module requirements. Stakeholders may opt to limit an AMI pilot to a specific customer rate class or initiate AMR functions but not DA.

AMI Technology Assessment Phase II clarifies AMI program objectives and establishes a five-year technology work plan to achieve potential results. During this stage, stakeholders develop a realistic "wish-list" to serve as a guide for investments and specific goals. During the second phase, stakeholders may use meter performance data from the first implementation phase to prioritize system enhancements and propose phased implementation, focusing on maximum benefits. Identifying the big picture and a blending of options may avoid "oops ~ we didn't think of that" moments later.

The AMI pilot implementation occurs in three phases, each of which allows stakeholders to analyze captured data to determine the effectiveness of that phase. AMI Pilot Phase I centers on mapping the pilot area and verifying the performance of specific metering and communication technologies. AMI Pilot Phase II introduces trial time-based rates and collects data to determine the specific rate design effectiveness of on the pilot and focuses on economic benefit to customers. AMI Pilot Phase III uses findings made during Phase II to continue time-based rate design. Aggregated data collected in AMI Pilot Phases I and II reveal optimal rate designs to achieve maximum economic benefit. The AMI Pilot Phase I begins after completion of the AMI Technology Assessment Phase I. The second phases of parts, assessment and pilot, occur at the same time, after completion of the AMI Pilot Phase I.

Indiana Applications

Indiana has enjoyed historically low electricity prices; a 2005 EIA report ranks Indiana as the seventh lowest state in average retail price at 5.88 cents/kWh. In addition, Indiana has high energy consumption, ranked eleventh in overall energy consumption and ranked fourth in industrial sector consumption. Energy cost increases will have significant impacts on the Indiana economy and Indiana ratepayers due to these high levels of consumption. This concern along with healthy load growth and developing opportunities for price responsive demand side resources to participate in regional energy markets have prompted some Indiana utilities to embrace energy efficiency and demand response program expansion through AMI. Indiana utilities also foresee future AMI benefits of improved forecasting and billing accuracy, managing operating costs, improving service deliverability and providing tools for customers to manage energy consumption.

Many Indiana electric utilities including Rural Electric Membership Cooperatives (REMCs), municipal owned utilities and investor-owned utilities (IOUs) have installed AMR systems and DA devices. For example, Hendricks Power Cooperative utilizes a blended AMR system using power line carrier technology (through TWACS) and CellNet technology to accommodate suburban and rural areas. In addition, it has installed DA devices including reclosers and motor-operated airbreak switches which use a mesh-network 900 MHz radio system for communication. Anderson Light and Power Municipal is in the process of installing an AMI system to serve approximately 34,000 customers. Indianapolis Power and Light (IPL) also uses the CellNet AMR system for approximately 450,000 customers. While this is not considered AMI, IPL's system has been saving meter labor expenses since it was fully operational in 2000 and has been integrated with its Outage Management System to predict and verify outages. IPL also has installed intelligent switches as part of a DA program to automatically isolate faulted circuit sections and restore service to the largest number of customers possible in several areas of its territory.

Conclusion

We have identified the economic and reliability concerns facing the U.S. electric power system and posited a partial solution: AMI. Yet, significant costs and system integration impair the implementation of a comprehensive AMI program, including DA. Utility staff and regulators must evaluate benefit and costs, maximizing both economic and reliability benefits and minimizing costs. A collaborative approach with utilities and other stakeholders can prove a successful strategy to incorporate all party interests and objectives. Technical knowledge from actual system deployment will drive decision making as the AMI projects evolve. In addition, stakeholders may apply mutual understandings gained from collaborative design and implementation to other programs and discussions of electric industry issues.

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