Proposed Regional Approach for Smart Grid Deployment In the Mid-Atlantic Region

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Background

The significant increase in retail rates experienced recently in several Mid-Atlantic states has resulted in a renewed interest in demand response (DR) programs to help mitigate high wholesale market prices and to give retail customers new tools for lowering their monthly electric bills. A recent report prepared by the Brattle group on behalf of PJM and the five MADRI state electric utility commissions has indicated that there could be substantial savings from even a modest amount of DR.[1] More specifically, the Brattle study estimated savings ranging between $57 million and $182 million from a relatively modest 3% reduction in peak demand during the highest 100 hours of LMP prices in five transmission zones. The Brattle report also found that the five Mid-Atlantic states would benefit more if they worked collaboratively to reduce demand during peak periods rather than individually.[2]

With the substantial changes that have occurred in the Mid-Atlantic electric market environment in recent months, Mid-Atlantic electric distribution companies are rethinking their role as default service providers. At least two companies, Pepco Holdings Incorporated (PHI) and Baltimore Gas and Electric (BGE) have come forward with proposed new programs to offer demand response and energy efficiency alternatives to their retail customers. This is a significant change from the recent past where the role of a distribution company providing default service was limited largely to passing through wholesale power costs based on prices set at periodic auctions. Increasingly, even in a restructured electric environment, it appears that the electric distribution company will be called on to evaluate and implement both supply side and demand side strategies to help manage electricity costs for retail customers.

One of the key tools electric distribution companies are embracing for helping to implement new DR initiatives is advanced metering infrastructure (AMI). PHI and BGE have proposed AMI initiatives in Maryland where they would install advanced meters and a two-way communications infrastructure with all of their retail customers. PHI has also made similar AMI proposals in Delaware and the District of Columbia and is expected to also make an AMI proposal in New Jersey. Other distribution companies in the Mid-Atlantic Region are actively considering AMI investments. PSE&G for

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[1] The five Mid-Atlantic states participating in the Mid-Atlantic Distributed Resources Initiative (MADRI) include: Delaware, District of Columbia, Maryland, New Jersey and Pennsylvania.
[2] http://www.energetics.com/madri/pdfs/BrattleGroupReport.pdf

example has an ongoing pilot program to consider the effectiveness of new pricing structures enabled by AMI.

While electric distribution companies have emphasized the DR benefits associated with their AMI proposals, evaluations of AMI investments in other regions suggests that DR related benefits constitute less than half of the benefits realized from an AMI investment and DR benefits in and of themselves are not sufficient to justify AMI deployment. Southern California Edison for example, estimates that only 36% of the benefits it projects for its AMI investment can be attributed to DR.[3] The majority of benefits needed to support utility AMI investments are derived from anticipated improvements in several key utility operating functions including:

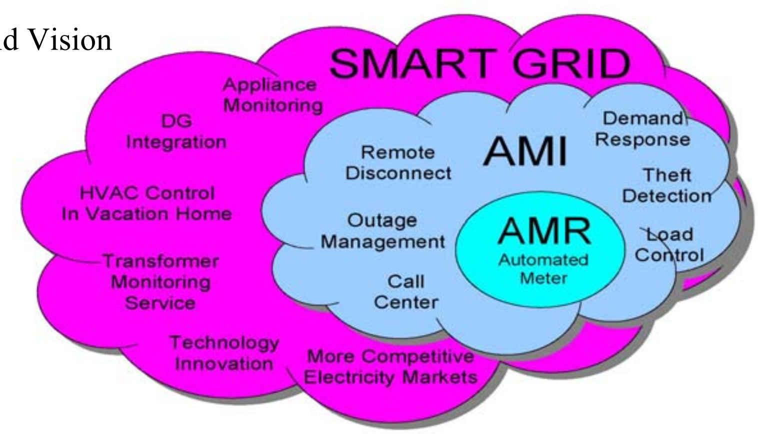
- Automated Meter Reading
- Remote Customer Disconnect
- Outage Management
- Call Center Integration
- Theft Detection
- Distribution Automation

<u>Moving Beyond AMI to Adopt a Smart Grid Vision</u>

In evaluating utility AMI proposals, a key consideration for utility regulators and other decision makers is the scope of the planned investments and who is likely to benefit from these large investments. It is also important to consider whether the planned investment scope extends beyond utility operational considerations, to encompass additional functional capabilities commonly associated with a Smart Grid concept to include activities and potential benefits that may be outside the scope of traditional business activities for utilities.

Figure 1 depicts how a utility AMI investment can be designed to provide a platform to enable subsequent Smart Grid activities.

Figure 1
Smart Grid Vision



[3] SCE December 21, 2006 Filing, Volume 1 page 26; http://www.sce.com/PowerandEnvironment/ami/

For example, technology exists today to monitor the current draw on individual appliances within a home. It is difficult to see how this type of data would be useful to most electric distribution companies other than for special market research type activities. As a result, this type of functional capability is not expected to be included in most utility AMI proposals. However, this data could be extremely useful to non-utility third party service providers, such as HVAC companies. An HVAC company could, for example, use information on an air handling system to determine when an air filter needs to be changed or recommend preventative maintenance. By designing the AMI system to provide the type of data that all market participants, not just the utility, find useful and by providing timely access to this data, substantial innovation can occur. This can spawn new types of market activities and substantial additional benefits that go beyond the relatively narrow benefit stream defined by an AMI investment intended primarily to benefit a utility.

Key Considerations for Regulators

The challenge Mid-Atlantic regulators face is how to set their own Smart Grid agenda. If regulators do not take a proactive approach to AMI, their options will likely be limited to responding to utility agendas to build AMI systems. In this case, states will run a significant risk of forgoing the significant benefits they might otherwise realize if they were to adopt a Smart Grid vision and direct the utilities they regulate to develop the infrastructures and data access policies that will lead to the evolution of a Smart Grid.

In evaluating Smart Grid options, there are four key considerations for regulators:

- Functional Requirements
- Interoperability
- Technical Standards
- Data

Each of these considerations is summarized briefly below.

Functional Requirements:

By defining the functional requirements of the AMI systems that utilities build, regulators will have a significant impact on the type Smart Grid benefits that will be available. Figure 2 below summarizes the basic functional capabilities of the AMI system BGE plans to build. PHI has indicated it is considering similar capabilities for its AMI system.

Figure 2
BGE AMI Functional Requirements

• Automate meter reading • Two-way communications • Remote disconnect at or below 200 amps • Hourly data once per day • Time stamp meter data • Data to customer on day after basis • Data storage at meter • Outage management	• Remote programming • Bi-directional metering • Net Metering • Voltage monitoring • On-demand data access • Data security • Meter tampering detection • Support local display

Source: BGE Initial Comments MD Case 9111, July 6, 2007, page 2

Non-utility participants in Maryland's AMI working group have pushed back on some of the proposed functional requirements proposed by BGE. One area in particular that has caused a lot of discussion concerns the frequency of meter scans and how soon this data is available to market participants. Currently BGE plans to offer meter scans for residential customers no more frequently than at hourly intervals and to make this data available on a next day basis. PJM notes that its synchronized reserves market requires one-minute meter scans. EnerNOC believes that in the not too distant future "residential customers should have access to real-time pricing programs…and that a bona fide dynamic pricing platform will require at least 15 minute intervals, or possibly even 5 minute data intervals"[4]

Others such as Hydro One have demonstrated the substantial benefits that can be realized from in-home energy monitors that allow customers to see on a virtually real time basis how much electricity they are using and what the cost of using this electricity is. Market research conducted by Hydro One indicates that on average, residential customers reduce their electric consumption by about 6.5% just by receiving better information on how much electricity they are consuming. While BGE indicates it will support an in-home monitor, it is not clear that an in-home monitor will be supported by the PHI AMI system.

[4] Comments of EnerNOC submitted pursuant to MD Order 81448, page 2.

Interoperability Considerations

Currently it can take over 60 days for customers participating in PJM's Economic DR program to settle. The reason for this lengthy settlement process is that there is no automated system in place to verify participants' load reduction and calculating payments for this reduction. The current settlement process is based on manual calculations and manual transmission of data.

Consideration needs to be given to how data generated in the retail markets can be used to facilitate market activity at the wholesale level. This does not necessarily mean that additional functionality needs to be designed into an AMI system. It does imply, however, that as part of the design of an AMI system, consideration needs to be given to what types of data will be required for facilitating wholesale market transactions and how this data will be made available to wholesale market settlement processes.

Another major interoperability consideration is the interface with the customer side of the meter. For example, it seems desirable that there be a standard protocol for interfacing with smart thermostats installed on the customer side of the meter through systems build around an open architecture. However, PHI's AMI proposal contemplates that they will be the provider of smart thermostats based on a system architecture they design. An alternative would be for PHI to offer an open architecture for smart thermostats that would allow competing manufactures to provide this device, either in conjunction with a utility program or possibly as a completely separate service. This would allow vendors to offer services such as vacation home monitoring and HAVAC control that a utility is unlikely to consider offering.

Technical Standards

Regulators need to ensure that AMI systems are built to a consistent set of technical standards. Ideally these standards will be similar throughout the Mid-Atlantic region and PJM market footprint.

Figure 3 summarizes the major categories for which it is suggested technical standards need to be considered and indicates the standards initiatives already underway in these areas.

Figure 3
AMI Technical Specifications

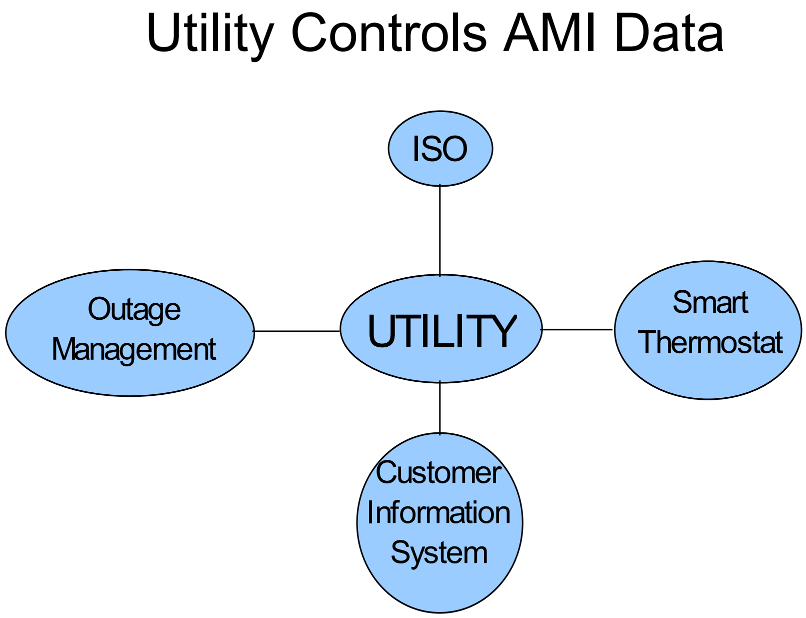
Focus	Name	Description
Grid Architecture	DOE Office of Electric Delivery and Reliability	Supports a variety of grid R&D and standards efforts.
	GridWise Architecture Council	Formed with the support of DOE with the ambitious goal of creating the technical architecture for the next 30 years of grid progress.
	Intelligrid	Managed by EPRI, the Intelligrid Architecture is a set of communications standards and protocols. It also includes demonstration projects such as fast simulation modeling, an advanced consumer gateway/portal, and communications architecture for distributed resources.
Market Structure	North American Energy Standards Board (NAESB)	An industry forum for standards to create a seamless wholesale and retail marketplace for natural gas and electricity. Several committees are working on smart grid-related standards for the sale of electricity at both the retail and wholesale levels.
Metering	OpenAMI Task Force	A consortium dedicated to standard platforms for advanced metering and demand response.
Transformers	EPRI Advanced Distribution Automation (ADA) program	Among other things, ADA is working on a "intelligent universal transformer" that would do away with the need to custom build every transformer.
Remote Monitoring	Zigbee	ZigBee is a wireless standard that addresses the unique needs of remote monitoring, particularly on customer premises.
	I-Grid	Developed with support from the DOE, I-Grid is a system for low-cost, real-time grid monitoring and reporting over the Internet. It may eventually include a national repository of power-quality data.
Distributed Generation	NREL Interconnection Standards	The National Renewable Energy Laboratory (NREL) works closely with the IEEE and other organizations to produce uniform interconnection standards that will be "the foundation of widespread and inexpensive integration of distributed power systems."
	UL Distributed Generation Equipment and Energy Sources	This Underwriters Laboratories program includes certification of fuel cells, photovoltaics, wind turbines, and other distributed resources, as well as certification of inverters, converters and controllers.

Prior to approving utility AMI investment proposals, regulators should understand how consistent the proposed AMI systems are with these standards as well as any other standards they believe are appropriate.

Data

One of the most difficult issues regulators are going to have to address in evaluating AMI proposals is the data that is developed through AMI systems. Many utilities believe that AMI is an integral part of operating a utility distribution system and believe they need to have sole discretion in determining what data is collected, how it is stored and formatted and who has access to it and when. Figure 4 summarizes this perspective and seems to reflect the utility administered meter data management system (MDM) that PHI is contemplating. While this model can appear relatively simple, in actuality, this type of AMI data model can become extremely complex from an overall market perspective when each utility develops its own type of AMI meter data management system based on its particular operating considerations.

Figure 4
Utility AMI Meter Data Management Model

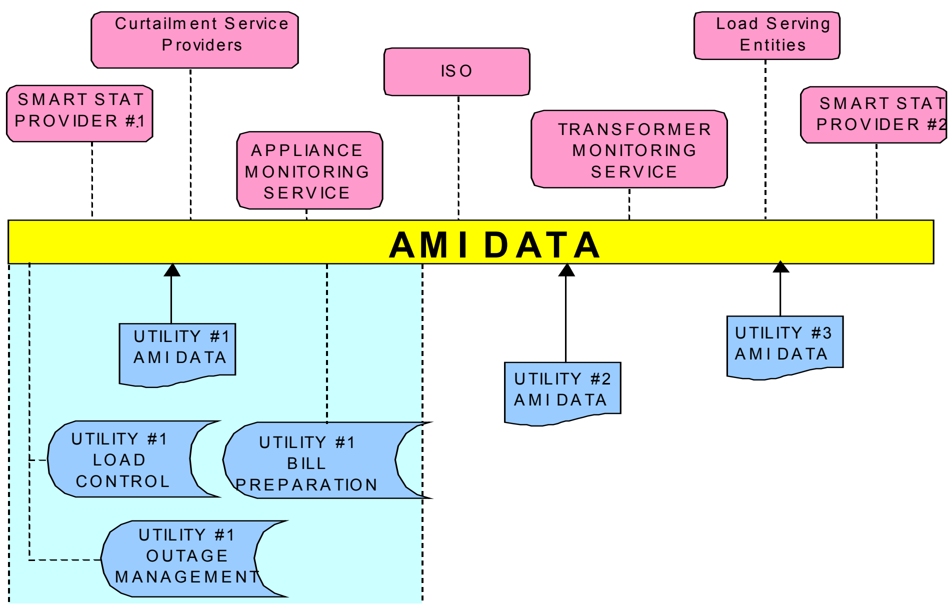


In the Maryland AMI working group, several non-utility market participants voiced their concern with the meter data management model depicted in Figure 4. EnerNOC for example, argues that it is "inadvisable to limit communication of AMI data from customers' meters to only the utility, resulting in [the] utility controlling the flow and dissemination of data to the customer or customers designated supplier of services.[5] EnerNOC suggests that customer usage data is owned by the customer and that "third party providers should have direct, unfettered access to the advanced meters at customer's sites. This direct access ensures that the third party providers are given the same accessibility to the data as the utility."[6]

Figure 5 depicts an alternative way of collecting AMI data and making it available to other potential market participants including third party smart thermostat providers, PJM, load serving entities and appliance monitoring services.

[5] Reply comments of EnerNOC, MD case 9111, page 4.
[6] Reply comments of EnerNOC, MD case 9111, page 3.

Figure 5
Open Access AMI Meter Data Management Model



This approach is similar to what the provincial government of Ontario Canada has mandated. In Ontario, distribution companies install the AMI infrastructure to collect smart meter data. A separate entity is responsible however for warehousing the data and making it available to market participants, including the distribution utility.

Proposed Regional Approach to Smart Grid Development

Individual states in the Mid-Atlantic face significant challenges in evaluating and shaping utility AMI proposals. AMI represents a complex technical challenge. Commission staffs, for the most part, do not have personnel trained in this area and lack the financial resources needed to hire outside consultants. Without obtaining additional help, individual states run a significant risk of simply responding to utility AMI agendas and forgoing any opportunity to move forward with their own Smart Grid agendas which could potentially create more competitive and robust market activity and substantially greater customer benefits.

An additional consideration for states is the need to coordinate their activities with one another. As indicated previously, the Brattle study quantified the significant benefits associated with the Mid-Atlantic states working together to foster increased DR in the region. Similarly, it is believed that individual states would benefit if they approached AMI issues regionally rather than individually. It makes little sense, for example, to use one set of AMI standards in Maryland and another set in New Jersey. Similarly, many of the interoperability and functional specification issues are common throughout the region and are probably best dealt with regionally rather than on an individual state basis.

It is suggested therefore that the Mid-Atlantic states work together in a collaborative fashion to put forward there own agenda for developing AMI systems that will support a Smart Grid vision. The key issues that will need to be dealt with in this regard include:

- Defining the Minimum Technical Requirements for the AMI system
- Resolving Interoperability Issues
- Establishing Appropriate Technical Standards
- Determining How to Collect and Manage AMI Data

Recommended Next Steps

To begin implementing a regional AMI deployment strategy is recommended that states consider the following:

1) Establish an appropriate regional working group forum. Alternatives could include a MADRI AMI working group or possibly a PJM working group.
2) Identifying appropriate technical experts and a budget for retaining these experts.
3) Securing the necessary financial resources.
4) Developing a work plan and timeline for completing the activity as expeditiously as possible – no more than 6 to 9 months.