Staff Report on Minimum Functionality Standards for Advanced Metering Infrastructure

Case No. U-15620

Prepared by Staff of the Michigan Public Service Commission

October 1, 2008
INTRODUCTION

On April 24, 2007, the Commission issued an order in Case No. U-15278, directing staff to begin a collaborative process to monitor smart grid infrastructure initiatives and to establish evaluation criteria and standards when options appear to be cost-effective and practical to implement. That order recognized that “smart grid infrastructure initiatives” was a broad term covering a range of developments from customer level to distribution and transmission–level developments. The efforts of this collaborative were to be summarized on an annual basis in a Staff Report.

The April 29, 2008 Staff Report in Case No. U-15278 recommended that the Commission begin a proceeding to receive public input on the development of criteria for minimum functionality standards and rate recovery of capital expenditures on advanced metering infrastructure (AMI).

Subsequently, on July 1, 2008, the Commission indicated in an order in Case No. U-15620 that it is time to begin an investigation into minimum functionality standards for advanced metering infrastructure. The order invited interested parties to provide comments by August 1, 2008 on nine questions posed by the Commission and directed that the Staff file this Report on the investigation by October 1, 2008. Eighteen parties filed comments to the questions posed in the order. These comments are summarized in Attachment A to this Report.

On July 16, 2008, at the request of several parties, Staff met with Detroit Edison, Consumers Energy, Indiana Michigan Power Company and Michigan Electric Cooperative Association, to discuss the Commission’s order in more detail. At that meeting, Staff circulated

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2 The staff report in Case No. U-15728 can be found at the following link: [http://efile.mpsc.cis.state.mi.us/efile/docs/15278/0007.pdf](http://efile.mpsc.cis.state.mi.us/efile/docs/15278/0007.pdf)
a copy of a draft of the Louisiana Public Service Commission’s Final Proposed Rule, which is attached to this Report as Attachment B.

BACKGROUND

Advanced metering infrastructure initiatives are an important tool to modernize the electricity grid, reduce peak demand and reach energy efficiency goals. Both the 2005 and 2007 comprehensive energy bills passed by the U.S. Congress provide the building blocks that support advanced metering initiatives, which in turn provide direction for states to investigate opportunities for incorporating AMI and demand response into their policy initiatives. Following is a brief synopsis of recent federal energy legislation and policy directives that are related to smart grid and advancing the efficient use of the electric grid that were relied upon by Staff in developing its recommended Guidelines.

Federal Policies:

Energy Policy Act of 2005 - The Energy Policy Act of 2005 (EPAct) amended the Public Utility Regulatory Policies Act of 1978 (PURPA) Section 1252 to require establishment of a “smart metering” standard, where utilities offer customers time-based rates (such as time of use (TOU) pricing, critical peak pricing (CPP), real time pricing (RTP)) or in the case of large customers, capacity credits. The time-based schedule “shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology…” Commissions were not required to adopt these new standards but must consider them. Section 1252 states the policy to encourage “time-based pricing and other forms of demand response, whereby electricity customers are provided with electricity price signals and the ability to benefit
by responding to them.” It further states that “deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy capacity and ancillary services markets shall be eliminated.” The legislation directed states to commence consideration by August 2006, and to complete consideration within a year. In addition, EPAct required the Federal Energy Regulatory Commission to prepare reports assessing electric demand response resources from all consumer classes. The 2006 and 2007 reports, *Assessment of Demand Response and Advance Metering*[^4], included an analysis of the saturation and penetration rate of advanced meters and communication technologies, devices, and systems.

**Energy Independence and Security Act of 2007** - The Energy Independence and Security Act of 2007 encourages the deployment of smart technologies (i.e. real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, distribution automation, and directs the integration of “smart” appliances and consumer devices. In addition, the Act directs the Secretary of the U.S. Department of Energy to work with other agencies, electric utilities, and states to develop advanced techniques for measuring peak load reduction and energy efficiency savings from smart metering, demand response, distributed generation, and electricity storage systems. The legislation also established a Federal Matching Fund for Smart Grid Investment Costs, dedicated to supporting metering devices, sensors, control devices, and other devices integrated with and attached to an electric utility system, retail distributor, or marketer of electricity that is capable of engaging in Smart Grid functions. Funding for such programs is available until 2012, while a Smart Grid Advisory Committee and Smart Grid Task Force established by the legislation are funded through 2020.

National Association of Regulatory Utility Commissioners (NARUC) - The Demand Response and Metering Report (2007) indicates that AMI has continued to gain support from additional initiatives. The resolution passed at the 2007 Winter Meeting of NARUC calls for “elimination of barriers to advanced metering” and recommends that state commissions provide investment incentives and accelerated depreciation to help utilities quickly recover their advance metering investments.5

State Policies:

The federal-level attention to advanced metering and the technologies it enables has provided the impetus for many state-level investigations. Some states, notably California, began investigations well in advance of federal level encouragement, largely in response to an energy crisis experienced there in 2002. Michigan began a preliminary investigation in response to the EPAct Section 1252 compliance requirements when the Commission opened a proceeding in Case No. U-15813 to consider the smart metering tariff provisions offered by the electric utilities subject to its jurisdiction that met the qualifying criteria of annual sales volumes in excess of 500,000 MWh. The Commission concluded that all but two of the eight qualifying utilities offered time-of-use tariffs to all customer classes and directed further proceedings for the two non-compliant utilities. In that proceeding, the Commission recognized the preliminary nature of the tariff offerings in Michigan, reserving the right “to revisit the topic of optional time-based rate schedules in future proceedings as the need for customers to make use of the advantages of smart metering provisions increase and as new developments in this area are achieved”.

Following is a brief summary of some of the state’s policies reviewed by staff.

**California:** In 2002, the California Public Utility Commission (CPUC) opened rulemaking to further develop demand response and advanced metering policies. The rulemaking was largely related to demand response initiatives but one component focused more on advanced metering policies which included the state requirement that all investor-owned utilities file AMI project proposals. These proposals were required to meet minimum functionality standards, be cost effective and get prior approval for AMI deployments.  

California was at the forefront of the effort to define minimum functional requirements criteria for advanced metering infrastructure and their version is summarized below:

- Capable of supporting various price responsive tariffs (CPP, TOU, RTP)
- Capable of collecting energy usage data at a level that supports customer understanding of hourly usage patterns and their relation to energy costs
- Capable of allowing access to personal energy usage data such that customer access frequency did not result in additional AMI system hardware costs
- Compatible with applications that provide customer education and energy management information, customized billing, and complaint resolution
- Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability
- Capable of interfacing with load control communication technology

Other California measures that promoted demand response and advanced metering were the Statewide Pricing Pilot investigation of time-based pricing strategies, an Advanced Metering Initiative involving one IOU’s plan to replace 5 million standard meters with AMI systems, and the Energy Action Plan II which creates a “loading order” where utilities must prioritize their resource procurements by focusing on energy efficiency first, demand response second, followed by renewables and clean fossil-fueled distributed generation and central-station generation. This

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emphasis on demand response in the Energy Action Plan is attributed to being one of the key energy policy drivers for California’s AMI initiatives, in addition to the PUC requirement that investor-owned utilities meet 5% of their system peak load requirement by 2007 with demand response.\textsuperscript{7}

**Texas:** In 2005, the Texas legislature passed HB2129, which stated in part “in recognition that... new metering and meter information technologies, have the potential to increase reliability of the regional electrical network, encourage dynamic pricing and demand response, make better use of transmission and generation assets, and provide more choices for consumers, the legislature encourages adoption of these technologies by electric utilities in this state.” HB 2129 addressed the cost recovery issue by allowing a surcharge to recover investments.

In May of 2007, a rulemaking (Project 31418) related to advanced metering was completed by The Texas Public Utilities Commission.\textsuperscript{8} Among other things, the rulemaking defined the minimum system features (e.g. functionality) of advanced metering systems required in order to obtain cost recovery. Rule 25.130 is the Advanced Metering Rule and its purpose is to “authorize utilities to assess nonbypassable surcharge to use to recover costs incurred for deploying advanced metering systems that are consistent with this section; increase the reliability of regional electrical network; encourage dynamic pricing and demand response, improve the deployment and operation of generation, transmission and distribution assets, and provide more choices for electric customers.”\textsuperscript{9} The rule features minimum advanced metering capabilities, communications with Home Area Networks, data access, deployment information and cost recovery. The minimum advanced metering system features in this rule are summarized as:

\textsuperscript{7} Ibid
\textsuperscript{8} [http://www.puc.state.tx.us/rules/rulemake/31418/31418.cfm](http://www.puc.state.tx.us/rules/rulemake/31418/31418.cfm)
\textsuperscript{9} Ibid, page 82
- Remote meter reading
- Two-way communications
- Remote connection and disconnection (<200 amp meters)
- Time-stamping of meter data
- Direct, real-time access for customer and retailer to meter data
- Ability to send price signals to customer
- Fifteen minute or shorter interval data
- On-board meter storage of data
- Open standards and protocol
- Communications with customer premises
- Upgrade capability

In a September 2006 report to the legislature, the PUC of Texas explained that the purpose of the minimum functionality “is to ensure that the best combination of operating capabilities, consumer benefits, and operating reliability are realized.” Utilities would be able to decide what technology is best for their systems, as long as the advanced metering system meets the functionality and other standards prescribed in the rule.

**Louisiana:** In May 2006, the Louisiana Public Service Commission began an examination of the public benefits of “adopting rules, new tariffs, and/or other regulatory mechanisms that would promote (or require) the use of wireless metering in Louisiana.”10 A Final Proposed Rule was drafted in August of 2007 (R-29213) and commission approval is pending. The Louisiana Final Draft Rules address the “terms and conditions under which electric and/or combined electric and gas utilities can seek the recovery of costs associated with the implementation of new advanced metering and demand response programs, including the integration of existing advanced metering or demand response programs into such new programs.”

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10 Docket R-29213 subdocket A. Note that the Draft of the Final Proposed Rule was not posted in the docket and was obtained via email correspondence with the web contact listed on the electric page http://www.lpsc.louisiana.gov/electric.asp
Those rules provide for a pilot certification process for demand response (DR) and advanced metering system (AMS) programs. In addition, the rules describe the requirements for certification of a pilot program including minimum functionality, filing requirements for pilot certification programs monitory requirements and cost recovery. The Louisiana rule is uniquely flexible in that it defines the minimum functionality requirements for AMS as a system that shall have “one or more” of the following advance system capabilities which are summarized below:

- Automated or remote meter reading
- Two-way communications
- Support for dynamic or incentive pricing and ancillary services (Where appropriate)
- Remote disconnection and reconnection capabilities
- Ability to send price signals to the customer
- The capability to monitor compliance with load management and DR programs, and the ability to provide information on whether the customer has complied with program requirements and the compensation, if any, to which they may be entitled for their participation in any incentive-based programs
- Hourly or shorter interval data
- Storage of meter data
- Communication between the meter and its head-end system shall be consistent with an open standard architecture
- Capability to allow customers to pre-program response of individual appliance upon notification of demand response or load control events

**Maryland:** In June 2007, the Maryland Public Service Commission issued Order No.81148, which directed investor-owned utilities and Commission Staff to participate in an AMI/DSM collaborative with other interested parties. The Commission directed the collaborative to submit a report by July 6, 2007, with recommendations on four issues relating to AMI and DSM programs: (1) technical standards for, and operational capabilities of, advanced meters; (2) the extent to which demand side management programs are to be offered in the state on a competitively neutral basis; (3) recovery of costs of demand side management programs; and (4) the appropriate measure(s) of cost effectiveness of demand side management programs to be employed in the state. A report was filed, but the collaborative was unable to reach a
consensus on all four items. Participants then filed individual comments on the report. The
Commission subsequently issued Order No 81637 (Case 9111)\(^{11}\) addressing three of the issues
raised: the establishment of standards for AMI programs, the appropriate method of cost
recovery for the companies to use in designing these programs, and company targets for
reduction in electric consumption. The order lists twelve minimum requirements that “shall be
assumed in the electric company’s proposals to implement an AMI system” and allows for the
utility to exceed these minimum standards as long as cost-effectiveness of the capability is pre-
approved by the commission:

- A minimum of hourly meter reads delivered one time per day
- Non-discriminatory access for retail electric suppliers and curtailment service providers
to meter data and demand response control functions that is equivalent to the electric
company’s own access to those functions
- AMI shall be implemented for all customers of the electric company
- Metering and meter data management should generally continue to be an electric
company function including the implementation of AMI/MDM. Metering and data
management options may be considered for larger non-residential customers (this does
not exclude any customer from a requirement that their AMI shall at a minimum be fully
consistent with all AMI standards). For example, if an industrial or commercial customer
(and its retail supplier or CSP) requires more frequent meter reads or downloads, the
utility shall work in good faith to accommodate such requirements
- All AMI meters shall have the ability to monitor voltage at each meter and report the data
in a manner that allows the utility to react to the information
- All meters shall have remote programming capability
- All meters shall be capable of two-way communications
- Remote disconnect/reconnect for all meters rated at or below 200 amps
- Time-stamp capability for all AMI meters
- All meters shall have a minimum of 15 days of data storage capability on the meter
- All meters shall communicate outages and restorations
- All meters shall be net metering and bi-directional metering capable

QUESTIONS ASKED BY THE COMMISSION

1. Should the Commission prescribe functionality standards and criteria for AMI
deployment approaches, technologies, and functions?

\(^{11}\) http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction.cfm?CaseNumber=9111
Most parties submitting comments recommended that the Commission establish minimum functionality standards to be achieved. Utilities were opposed to the Commission setting standards relating to deployment approaches, preferring flexibility in managing AMI deployment. Staff agrees. With respect to technologies, there was consensus that the Commission should not promulgate technology or software-architecture related standards. These standards are best achieved by standards-setting organizations, such as ANSI, IEEE, and AMI-ESAC who have the industry support and expertise to develop and promulgate non-proprietary national standards. Because AMI implementation is still in its early phase, such national standards are still in the process of being developed, and various industry groups are advocating competing standards.

It is reasonable to expect the development of universal industry standards for AMI in the near future, in light of the number of industry groups that have been created for the purpose of open sharing of information and collaboration on standards,. Michigan utilities should be encouraged to participate in these groups. Staff supports open standards that use available technologies so that robust competition between metering, smart appliance and PHEV industries can occur. The Commission’s Technical Standards for Electric Service (R 460.3101) contain rules relating to metering, engineering, etc. The Staff recommends that at the next update of the Technical Standards, consideration be given to incorporating any then existing national technology standards or industry practices. If there are no such standards at that time, or if the Commission wishes to act earlier, then recommends that relevant portions of the Louisiana Commission’s Final Proposed Rule (Attachment B) be incorporated into the proposed rule changes.
2. To what extent should advanced-metering technologies and functions be standardized and to what extent should utilities be able to select functions on behalf of customers?

Most parties recommended that the Commission focus on functions rather than technologies. It would be reasonable for the Commission to establish expected capabilities that advanced metering would provide, but leave the selection of the specific technology to the discretion of the utility. Thus, any functionality standards set by the Commission should be technology neutral. For example, the selection of the type of communication infrastructure upstream of the meter, such as a radio-frequency local area network (LAN) or a broadband over power line (BPL) LAN should be left to the discretion of each utility. As WE Energies points out, a technology that works well in Detroit may not be appropriate for the sparsely populated areas of the Upper Peninsula. A focus on functions rather than technologies will ensure that customers will receive the types of services they expect regardless of the specific technology involved.

Utilities should have the appropriate flexibility to build upon the minimum functionality in a way that maximizes customer involvement and interaction with the AMI system, providing flexibility and appropriate choices for the customer. Options selected on behalf of customers should provide benefits exceeding costs.

3. To what extent should standard protocols for the information produced by advanced meter be prescribed?

Individuals providing comment were divided on this issue. Some believed that it would be helpful for the process to have some standards, but others argued that, due to the evolving
nature of the various protocols, selection of a preferred standard by the Commission would be premature.

It is our understanding that widely-accepted standard protocols for devices that communicate with smart meters through a home area network (HAN) do not currently exist for advanced metering, but they are being developed in various venues. We recommend that when a standard is approved by an industry, national, or international standards-setting body, the Commission should review it to ensure vendor-neutrality and then incorporate it into the Technical Standards for Electric Service. Staff recommends that meter information be available to customers simultaneously through the utility’s web portal and through a HAN gateway inside a customer’s premise. For security reasons, access should be password protected.

4. **Should the Commission establish minimum functionality for the recovery of AMI investment by utilities?** The Commission is considering AMI minimum functionality guidelines that address:

* remote software upgrade capability;
* remote shut-off and turn on capability;
* accommodation of net metering and distributed generation;
* prepaid service options;
* interoperability with future smart grid;
* two-way connectivity with intelligent appliances and other enabling devices;
* customers’ ability to monitor their energy use.

There was general agreement that the Commission should establish levels of functionality that would specify the minimum level of acceptable service. Staff believes that all of the features listed in the question are integral to the AMI business and that these capabilities should
be available in the marketplace. Staff suggests that guidelines may not be an appropriate mechanism for this purpose, because, it is our understanding that guidelines are only binding on the Commission and not on regulated utilities or any other party. If more formal adoption of standards is desired, we recommend rulemaking or a case-by-case process.

5. **In assigning possible deployment approaches and advanced-metering technologies and functions, how should the costs and benefits to utilities and customers be considered?**

   Staff supports the position set forth by most responders that investments in AMI be treated the same as any other capital expenditure in terms of each utility performing due diligence and justification of AMI investments by demonstrating adequate cost savings and improved customer service on a case-by-case basis. Costs and benefits of AMI programs should be evaluated to determine if they are reasonable and prudent as part of normal rate case proceedings for each Michigan utility.

6. **The Commission is considering open-source, non-proprietary guidelines for advanced meters. Have these systems been successfully implemented elsewhere? If the Commission prescribes guidelines for open-source, non-proprietary systems, what should these guidelines say?**

   Based on the comments received from Consumers Energy, it is our understanding that adherence to “open standards” for data format and data communications will lead to better interoperability between different vendor’s devices and should provide cost benefits for utilities over the lifecycle of these systems. The term “open-source” has special meaning within the technology sector and generally implies that human readable source code must be supplied with all applications distributed as “open-source” software. Open-source with its implications is not
conducive to AMI system requirements. Also, as previously noted, guidelines are only binding on the Commission, and thus not an advisable mechanism to use.

7. **Should the Commission prescribe guidelines to deal with information transmission and storage issues? Should it require a pilot project or gradual deployment of advanced meters, in recognition of the volume of information that market participants will have available from advanced meters?**

   Clearly, pilot projects of AMI make sense and are advisable to test the system’s functionality at a small level before a large investment takes place; although, some parties argued that a pilot cannot validate full system performance. Staff is not aware of any reason why requirements for AMI information and storage should be more or less stringent than data acquired by any other means. As noted in prior answers, guidelines would not be an appropriate method to use.

8. **To what degree is the security of AMI a concern, and what level of security should be designed in the system?**

   Staff agrees with all individuals providing comments that security of the system should be a primary concern to utilities when selecting, implementing and operating AMI systems. It is vital to have the necessary security to prevent a hacker from tampering with the system equipment or altering meter read data. We understand from the comments that there are existing security standards relevant to AMI, including: FERC, NERC, NIST, ISO/IEC, and AMI-SEC.

9. **Are there other issue the Commission should address in this proceeding?**

   Although various comments were received, the remaining issue that Staff considers most important involves the effects of AMI on the relationship between the utility and its customers, especially as it relates to collection and shut-off protection. Through long experience, the
Commission has well-established procedures to ensure an equitable relationship between a utility and its customers. These procedures are necessary because, unlike most other businesses, a utility is, by definition, a natural monopoly. Before AMI becomes widespread, Staff recommends a review of the Commission’s Consumer Standards and Billing Practices (R 460.102) to determine what changes, if any, are needed.
Summary of Responses to Questions

1. Should the Commission prescribe functionality standards and criteria for AMI deployment approaches, technologies, and functions?

We Energies (0004): Due to the fact that the AMI industry is in its early stages, the AMI standards should be very broad and general as to not preclude installation of an emerging technology and not to stifle competition.

Indiana Michigan Power (0006) – The MPSC should set minimum functional standards rather than specific technology standards. A suggested set of minimum functional standards should include (1) remote reading of all meters, (2) remote disconnect/reconnect for 200Amp and below service, (3) support for net metering, (4) remote meter software upgrade capability, (5) customers’ ability to monitor energy use, (6) support for communication with in-home devices, (7) support for future customer program development, and (8) provides outage notification and restoration confirmation. Utilities should be allowed to offer other functions and specific consumer programs not defined as minimum functionality, which would be evaluated on their merits as they are developed. Multi-service functionality (electric and gas, electric and water) may be provided for, but should not be mandated. Specific standards prescribing the details of deployment would be neither necessary nor beneficial to utilities or consumers. The deployment approach chosen by a particular utility is grounded in the unique attributes of that utility. These factors include, but are not limited to: number of customers, geographic diversity, consumer attributes, and cost recovery. Prescribing a single deployment approach does not recognize the variability in these factors and could delay the progress of AMI. Development of technology standards is underway and is best completed by the industry and existing standards-setting bodies. Should the Commission desire to include specific technology standards, a well-defined waiver process that allows for a utility to not meet the standard for good cause should be included. I&M has initiated a cross functional project called gridSMART which is designed to provide customers with new levels of energy savings and control options and enhanced service reliability. I&M has presented to MPSC Staff an overview of gridSMART and a more detailed view of its proposed program of installing gridSMART to all customers in its Michigan service territory.

ABATE (0008): If a rigorous cost benefit analysis justifies the AMI deployment and the Commission has the legal authority to prescribe functionality standards and criteria, then they could be implemented through a rule making procedure.

Utility Workers Union of America (0009, 0010, 0011) – The Commission should adopt minimum functionality standards for any AMI deployment. The minimum functionality standards adopted by the California PUC appear appropriate for consideration in Michigan (see formal filing comments).

Wisconsin Public Service (0012) – Support basic functionality standards which make economic sense for the consumer are based on national standards and industry practice and based on well developed technology. AMI functionality beyond this core functionality is more complex, not yet
mature and still developing (e.g. capture of billing granularity beyond basic billing and control of customer and grid devices). Prescribing functionality should only be at the broadest level of detail until more cohesive national direction emerges. Utilities need flexibility and the Commission should prescribe expected results vs. the methods for achieving those results.

**DTE (0013):** The Commission should provide a baseline standard for MI utilities investing in AMI. The requirements should be incorporated into the Technical Standards as a guideline for MI utilities investing in AMI. Specific deployment approaches and technology selection should be the responsibility of the individual utilities because each utility is best suited to perform a comprehensive assessment of their territory and AMI technology suitability.

**Elster (0014):** Elster is in support of minimum functionality standards done by the Commission. The Commission should focus on promotion and determination of minimum functionality standards, guiding utilities as to the level of functionality that would be considered as “advanced” and sufficient to be considered for AMI. The Commission should not be involved in prescribing what kind of technology should be deployed by each utility, but instead this should be left with each utility. The Maryland Public Service Commission Order No. 81637 was given as an example, Pg. 5 of comments.

**Constellation (0015):** The Commission should not prescribe standards and criteria at this time. Until the tariffs of the electric utilities in Michigan are completely unbundled and truly reflect the underlying cost of the energy being consumed at any given time, rather than average cost prices that do not reflect the current cost of energy being consumed, subsidies of the utility’s generation via, e.g., securitization charges, or subsidy of one customer class by another, the conditions for such standardization do not exist. (Also there was much noted about Constellation’s affiliate, Baltimore Gas & Electric Company and the pilot program that is underway there and the guidelines prescribed with that program-pg. 2 of comments).

**Itron (0016):** The Commission should establish certain minimum levels of functionality to assist in guiding utilities and vendors to meet Commission policy and societal objectives. There should be a certain amount of latitude as to how each utility achieves these functions, and they should be minimum standards rather than absolute. Consideration needs to be given to which functions need to be immediately available and to those that may be beneficial for the utility’s future growth and migration, as well as end customers. The Commission should not mandate specific technology standards as long as the ones adopted by the utility are open and provide market participants access. The Commission should work collaboratively with each utility in technology selection, deployment, and implementation strategy to meet common objectives. Ultimately the utilities should be given the discretion to determine how best to integrate these new technologies to meet specific Commission mandated requirements. Each utility best understands how it can most effectively transition to take advantage of the functionalities available through deployment of AMI both in terms of internal business practices and ratepayer adoption.

**Consumers (0017):** Yes, the Commission should identify the minimum functions that provide customer value and benefits. Any Commission-adopted standards need to recognize that deployment approaches may vary among companies, and should be sufficiently flexible to allow varying approaches. A process to request waivers from established standards may be an approach.
to obtain the needed flexibility. In addition, any guidelines should be designed to encourage utilities to conduct pilots.

**MECA (0019):** MECA’s 9 cooperative members collectively have 320,000 electric meters and 8,500 gas meters and 80% of the total meters served by the electric cooperatives have been upgraded to the TWACS AMI systems over the last 5 years. Therefore, MECA believes that any initiative undertaken as a result of this investigation must recognize the existing programs implemented by the electric cooperatives.

**Trilliant (0020):** The Commission should prescribe minimum functional standards, especially regarding metering technologies in that they are in line with long standing and acceptable standards within the utility industry bodies (ex: American National Standards Institute). The Commission should consider the timing for the realization of benefits at specific stages during the scope of the project to motivate faster time to benefits and not wait until final completion. The Commission should not select specific and narrow standards for communication technologies or deployment approaches.

**Northern States Power (Xcel Energy) (0021)** – The Commission should provide a definition of advanced meter infrastructure (AMI) that defines minimum required metering functionality. The Commission should further prescribe only that technology proven and with foreseeable fiscal benefit to the utility and rate payer in a particular geographic region meeting the following criteria: (1) that it provides the ratepayer information for impacting their respective monthly energy portfolio. (2) That the fiscal consequences to the utility for AMI data and its delivery will be such that the utility is only strengthened to support service to the rate payer.

**Sensus (0022):** Utilities, vendors and the commission should collaborate on issues that would become utility mandated directives.

**Opsommer (0023 - revised 0005):** Yes, but neither the PSC nor the utilities should be able to prescribe mandates. California commission states “it is important that consumers have the ability to opt out of or into demand response and it is of utmost importance that consumers make their own energy decisions.” Consumers should be allowed to use programmable thermostats that visually show the real time cost and should not have to rely on checking websites or receiving emails. Automatic thermostats should have a manual override switch. Also rates for given months should be somewhat predictable based on season and time of day except for emergencies or truly unusual weather.

2. **To what extent should advanced-metering technologies and functions be standardized and to what extent should utilities be able to select functions on behalf of customers?**

**We Energies (0004):** Note the difference between standardizing technologies which restricts “how” a function is performed (e.g. standardizing on power-line carrier or radio frequency communication) vs. standardizing functions which restricts “what” activity is performed (e.g. remote shut-off or demand response). A technology that works well in Detroit may not work well in the sparsely populated areas of the U.P.
Indiana Michigan Power (0006): An approved AMI deployment should include a minimum set of functions such as those described by I&M in response to Question #1. Beyond minimum functionality, I&M supports giving customers a variety of options at different price points that enable customers to control their electricity consumption while also balancing their costs, lifestyle, and comfort level. Cost and technology considerations may dictate certain functionality, such as provision of hourly, day-after information to only residential customers with computers and internet access. For customers without computers, various cost-effective options will be made available through technology deployment and enhanced billing capability.

ABATE (0008): To the extent justified by a rigorous cost benefit analysis, the utilities could consider scalable meters and software that could be upgraded depending upon customer preferences.

Utility Workers Union of America (0009, 0010, 0011): The minimum functionality standards adopted by the California PUC appear appropriate for consideration in Michigan. It is not clear what the Commission means with respect to “functions,” however, if the intent of this question relates to the types of rate options or demand response programs offered to customers, it is recommended that any such options be offered to residential customers on a voluntary basis only.

Wisconsin Public Service (0012): Only minimum requirements should be developed. Utilities should have option of being able to cost justify benefits that meet needs of utility and customers.

DTE (0013): As utilities deploy systems and pilot new functions, the results should be shared and adjustments made to existing deployment plans. There are many utility industry forums that exist now for open sharing of information and collaboration on standards (Zigbee Alliance, Autovation, ANSI, NAESB, EPRI, EEI etc.). Many of these and others are working with utilities to develop universal industry standards for AMI and MI utilities should be encouraged to participate in these groups. Services offered to the customer beyond the standard tariff offering should be voluntary. The customer should be given adequate information to understand the benefits and risks with AMI.

Elster (0014): The ideal dynamic would be where the Commission rules on a set of minimum functions, and then there is allowance for each utility to determine if they would like to have additional functionality for their own systems and if so, they may choose to add requirements into their RFPs that are greater than the minimum requirements established by the Commission.

Constellation (0015): Constellation recommends that the Commission await the outcome of the pilot programs before issuing standards. It is essential that any projects (pilot or system wide) be competitively neutral. Alternative Electric Suppliers (AESs) and their customers must have the same access to the data and information as do the utilities and their supply customers. AESs must not only have the theoretical ability to access data on an equal footing with the utility, but must have the actual ability to do so. The platform including the underlying technology (hardware and software) should be done with AESs in mind.

Itron (0016): It should be within the utility’s charter to provide the infrastructure and functionality best suited to address each particular jurisdiction’s energy needs as defined and prescribed by the Commission. The utility is in the best position to select, deploy, manage, and
maintain the infrastructure required for advanced metering systems and address the significant
capital investments required for their installation. Each utility is intimately familiar with the
requirements of each consumer. Each utility should work with the Commission and other
stakeholders through interactive workshops to define the functions best suited to meet their
combined needs.

Consumers (0017): The Commission should avoid setting technology standards that limit the
utilities’ ability to be innovative and flexible with a technology that still has significant potential
for growth. Installations need to be flexible enough to allow for future enhancements. Customer
functions should also be addressed in the minimum functionality guidelines, but implemented in a
fashion that provides customers with options rather than forcing the purchase of specific load
management devices or appliances.

Trilliant (0020): The Commission should establish minimum system requirements and
capabilities because it is not desirable to the consumer to limit metering technology and functions
to a single standard because it will limit the functionality available or burden customers with the
cost only needed for a limited number of the population. There are functional standards that
should be left up to the consumer and made available by the utility under functional standards, for
example, demand response. The utility should provide tools and information to help consumers
manage their consumption but the decision to enable this technology should be up to the consumer.

Northern States Power (Xcel Energy) (0021): While similar metering technologies may be
available in multiple settings, distribution network and telecommunication network options vary
widely from situation-to-situation, and therefore only the defined AMI functions should be
standardized, keeping in mind that technologies should not be limited. However, technologies
should meet the requirements of the functionality by definition. Any additional functionality
beyond minimum requirements should have cost analysis to show benefit for ratepayer and utility.

Sensus (0022): Utilities should choose the best AMI system for their customers and the
Commission should decide on its position relative to real time pricing, in home automation and
energy conservation requirements.

Opsommer (0023 - revised 0005): Standardization should use openly available technologies so
that adequate competition between metering, thermostat and plug in industries can occur. True
consumer choice must be accommodated and AMI involvement must be determined by customer
with several options and not a “take it or leave it” approach. Who owns a programmable
thermostat must also be determined and clearly communicated with strong consideration being
given to consumers so they have a choice and control both in current homes and homes they move
into.

3. To what extent should standard protocols for the information produced by advanced
meters be prescribed?

We Energies (0004): There are currently no standard protocols and the industry continues to
evolve and perhaps in the future major AMI suppliers will voluntarily adopt standard protocols but
not in the near term.
**Indiana Michigan Power (0006):** The MPSC should endorse the protocol and information object standards that are currently under development for AMI by industry consortiums consisting of utilities, vendors, and research organizations, which are collaborating to develop a common set of industry standards that can be used nationally and internationally. These consortiums include: the National Institute of Science and Technology (NIST), the Department of Energy Federal Smart Grid Task Force, the Electric Power Research Institute’s (EPRI) IntelliGrid Project, the Utility Communication Architecture’s UtilityAMI initiatives, the GridWise initiatives and Utility Standards Board (USB). These standards are vendor-neutral and include, but are not limited to, the Common Information Model (CIM) and ANSI C12.19. This will allow Michigan to take advantage of the quality benefits of these standards without the costs of research, development, and adoption, and without the potential inadvertent result of prematurely eliminating some vendors and technologies prior to final completion of development work.

**ABATE (0008):** It is unknown what the information will be used for. Will there be two-way communication that allows customers to control their demands at peak periods and thus reduce their rates--- In any event, individual privacy should be protected.

**Utility Workers Union of America (0009, 0010, 0011):** Obviously, the utility will develop meter data management protocols that reflect their internal billing and accounting systems. While competitive energy suppliers have access to customer specific historical usage data with the assent of the customer, this question raises the issue of whether any other entity would have the ability to “mine” the vast array of usage pattern data that would be available with an AMI system and would seek to have access to such data based on standard protocols concerning how the data is presented or made accessible to those other than utilities. The Commission should carefully consider the privacy implications of developing such protocols.

**Wisconsin Public Service (0012):** There should be a distinction between information flows between meter and utility and those beyond the meter to the customer. Communication protocols between devices should be based on open standards to maximize long-term utilization. It is suggested that customer side networks could be based on internet protocol and the utility could provide the customer with information across the internet.

**DTE (0013):** DTE is in favor of standards, as they are necessary to promote interoperability of AMI and they limit the development of proprietary systems that are not easily interfaced with future technologies. Communication standards are noted as a key component in the definition of smart grid as defined in the Energy Independence and Security Act of 2007 (Section 1305). FERC 2007 Assessment of Demand Response and AMI also refers to AMI standards, along with ANSI standard C12.22 (p.5-6 for specific text of standards). Beyond the meter the Commission should focus standards on interoperability of home area network devices with the advanced meter, DTE supports Zigbee Alliance.

**Elster (0014):** If this refers to the meter data that is collected and then disseminated by the meter, then it should be noted that there are meter standards which apply in the U.S.A. and Canada, including American National Standards Institute C12 series “electricity Metering Standards”, which are developed in a rigorous process by technical experts that balance the interests of
marketplace stakeholders. Elster supports these efforts and serves on a number of ANSI standards committees and believe that such standards should serve as the basis for technical requirements.

**Constellation (0015):** Same responses as in questions 1 & 2.

**Itron (0016):** It is expected that the standard protocols for information exchange will be adopted by the major market players wherever it is technologically smart and economically prudent without the need of any regulatory guidance.

**Consumers (0017):** There may be a benefit for the Commission to specify some minimum guidelines. There is potential for future innovation and creative ways to use that data. Continued involvement with the standards activity taking place should be encouraged. Because of the evolving nature of the standards for 2 way AMI communications, the Commission should avoid setting specific standards (such as C12.22) that have not been widely accepted.

**Trilliant (0020):** ANSI standards should be continued and required in AMI.

**Northern States Power (Xcel Energy) (0021):** Protocols should be developed to support the information necessary for each AMI function. Information provided to the customer should be formatted so technologies and utilities remain transparent. Cross-subsidies should not be allowed between rate classes, or for other required options to meet customer requests.

**Sensus (0022):** This is already established through ANSI standards.

**Opsommer (0023 - revised 0005):** Meters should be able to communicate with a wide variety of thermostats and thermostats with a wide variety of after market devices. It should be of concern how long certain data should be reasonably stored for billing purposes before it is purged.

4. **Should the Commission establish minimum functionality for the recovery of AMI investment by utilities?** The Commission is considering AMI minimum functionality guidelines that address:

   - remote software upgrade capability;
   - remote shut-off and turn on capability;
   - accommodation of net metering and distributed generation;
   - prepaid services options;
   - interoperability with future smart grid;
   - two-way connectivity with intelligent appliances and other enabling devices; and
   - customers’ ability to monitor their energy use.

**We Energies (0004):** We Energies is very interested in many of the above mentioned functions and has actively tested and studied various functions. In general the functionality is a good thing but cost must be considered. Technology that works well in a city environment is not always the best solution in other areas.
**Indiana Michigan Power (0006):** I&M would support inclusion of minimum functionality standards such as those itemized in response to Question #1, and that successful installation of one or more of those functions define a compliant program. Alternatively, if compliance is determined by other mandated functionalities, a waiver provision should be available (utility service territory geography, for example, would determine different functionality for different utilities). I&M observes that development of interoperability with the future smart grid and two-way connectivity to intelligent appliances is too technologically immature to be a standard function at this time --- intelligent appliances and plug-in hybrid electric vehicle (PHEV) technology are still in development and no clear standards have emerged. Communication into the home as a platform for future development achieves the goal of minimum functionality without being too prescriptive too soon.

**ABATE (0008):** Some of these measures could be adopted if there is rigorous cost benefit analysis done and the Commission has legal authority. However, for safety and liability reasons, remote shut-off should not be authorized.

**Utility Workers Union of America (0009, 0010, 0011):** Remote software upgrade capability appears appropriate so that any AMI investment will not become obsolete with the development of new technology and functionality after the meter is installed. The Commission should not require AMI systems to install remote shut-off and turn-on capability (which is in the form of an additional module and not necessarily built into the meter itself) without a careful consideration and review of the significant policy and customer protection aspects of this aspect of AMI. Accommodation of net metering and distributed generation; interoperability with future smart grid; and two-way connectivity with intelligent appliances and other enabling devices are appropriate functionalities to require for an AMI installation. Functionality requirements for prepaid services options carry significant customer service and consumer protection policy implications. Such functionality is not operable with traditional AMI installation because it would require installation of a new payment system and an internal monitor to allow the customer to monitor their account status and usage. It is recommended that this functionality be dropped from the Commission’s consideration at this time. Functionality for customers’ ability to monitor their energy use is not necessarily part of a utility’s AMI proposal. For a customer to have access to their own energy use and usage pattern, either the customer or the utility would have to install a “smart” thermostat or other device in the customer’s home and would add significant costs to most AMI installations.

**Wisconsin Public Service (0012):** Minimum functionality guidelines can be addressed for all of the above functions but utilities should not be required to implement all of them to obtain cost recovery. Proven technologies are not available for all of the above functions or are available only at a high cost. Smart grid functionality is still evolving and even minimum functionality is difficult to evaluate and understand. As technologies and standards mature, the determinations of short-term and long-term benefits will become more cost effective. The Commission must re-evaluate depreciation and rate recovery philosophies to recognize the inherently shorter useful life of AMI systems.

**DTE (0013):** Notwithstanding the legal issues and considerations related to cost recovery, based on the cost-benefit analysis of each AMI business case, each utility should be allowed the flexibility to make business decisions as to whether it is prudent to incrementally invest in
technology to deliver the minimum functionality. If a utility finds that the benefits of pre-pay can’t be cost justified, they should not be required to make immediate investments for this feature. Also market conditions may not immediately justify an investment in AMI. For example, if a utility decides not to immediately invest in home area network thermostat controls, a utility may invest in technology that is capable of communicating from the meter with a home area network without replacing the meter; such investment should not be precluded from recovery. DTE supports minimum functionality and in addition they recommend that additional functionality be considered which would align with FERC recommendations for enabling of Demand Response and Advanced Metering (pg 8 for specific text of FERC guidelines).

Elster (0014): What matters most is the overall benefit to cost ratio is for all the stakeholders. A “total resources cost” test is used by many states and is defined in California publications. Some states approve a package of functionality based on the merits of the overall and other states “cherry pick” individual features. If the utility invests in advanced metering technology that meets or exceeds the minimum capability that the Commission sets forth in this rule making, then such investment should be recoverable in rates by the utility from its ratepayers.

Constellation (0015): If ratepayers are financially responsible for these programs, then the Commission must approve the details of the utilities’ programs. Customers of one major utility should not be paying more for lesser functionality than is available in a neighboring utility’s service territory. The ultimate program should be uniform and if a utility seeks to depart from the Commission requirements it runs the risk of having those investments not recovered from ratepayers.

Itron (0016): The Commission should establish certain minimum levels of functionality; they should be minimum standards instead of absolute. All of the features listed are integral to the AMI business case. These capabilities should be available in the marketplace, but not necessarily mandated by governmental agencies. The features of an AMI system should be componentized and promote open systems that evolve and can be interchanged by a utility to match its capital spending budget and migrate to new features and functions over time as they become cost effective.

Consumers Energy (0017): It is logical that a minimum set of guidelines be agreed upon as a basis for proceeding. If the utility meets these functionality guidelines, there should be a presumption that the expenditures are prudent. Consumers Energy supports the proposed guidelines with the following modifications:

- Remote programming & software upgrade capability over the life of the system
- Remote shut-off and turn-on capability (where reasonable)
- Accommodation of net metering and distributed generation
- Accommodation of prepaid services options
- Supports platform for future Smart Grid development and applications
- Two-way connectivity into the Home Area Network to support demand response and load management
- Customers’ ability to monitor their energy use

In addition, Consumers Energy recommends adding the following:

- Automated meter reading
• Interval data to facilitate future pricing options such as critical peak price, critical peak rebate
• Outage and restoration reporting & analysis support within Outage Management System
• Voltage reporting

In respect to prepaid services options, a disconnect switch is critical to support a robust and practical prepay program. However, once the program is established, we would need to investigate ways to include customers where a disconnect switch is not a viable option.

**MECA (0019):** The Commission must recognize the investments already made by electric cooperatives that have deployed AMI or advanced metering technology, regardless of whether it meets all of the functionality guidelines adopted.

**Trilliant (0020):** Remote software upgrade capability should be a requirement and it should also include remote programmability of the meters. The system should support remote shut off and turn on but it should not be a requirement on all deployed meters. Yes the Commission should accommodate net metering and distributed generation. Prepaid services should be a mandatory function but provided optionally to consumers. Open standards and interoperability should be a requirement to ensure the realization of the smart grid. Two way connectivity and support should be a requirement and customers should be able to monitor their energy use.

**Northern States Power (Xcel Energy) (0021):** The Commission should only establish minimum functionality for the recovery of AMI investment by utilities where the Utility can define fiscal service strength for itself and the rate payer of a given defined geographic service area based upon the availability of topographical, distribution network, and telecommunication network support for a given solution.

**Sensus (0022):** Yes to all.

**Opsommer (0023 - revised 0005):** Yes, but especially remote shut off must have security designed into it, true net metering functionality is critical and that connectivity with other devices must be a consumer decision, both in terms of whether or not to participate and whether such participation should be automatic.

5. In assigning possible deployment approaches and advanced-metering technologies and functions, how should the costs and benefits to utilities and customers be considered?

**We Energies (0004):** Investments in AMI be treated the same as any other capital expenditure in terms of each utility performing due diligence and justification of AMI investments by demonstrating adequate cost savings and improved customer service on a case-by-case basis.

**Indiana Michigan Power (0006):** I&M believes its gridSMART investments should be treated in a manner similar to supply-side investments (return on and of the investment at the utility’s authorized rate of return); related operation and maintenance expenses should be recovered, offset by any operational savings that result from gridSMART deployment; the net book value of any obsolete equipment (remove and replaced with updated equipment) should be recovered. I&M proposes contemporaneous recovery of the above revenue requirement using an annual tracking
mechanism that captures the costs and savings to the utility. Depreciation of new technologies
should be accelerated and depreciation of replaced technology should recognize its obsolescence.
Societal benefits may be estimated but should not be factored into the recovery calculation – the
utility should recover its net realized costs. Staff previously distributed the Notice of Final
Proposed Rule in Louisiana Public Service Commission Docket R-29213, Subdocket A for
comment. I&M commented on related portions of that document as follows: Article 3 – I&M
strongly endorses the position that certification of the project following Commission review should
provide assurance of recovery; Article 4 – I&M submits the following exceptions; pilot projects
should not be required if either I&M has deployed similar technologies in another jurisdiction or
another utility has deployed in Michigan or another state similar technologies and there is no
demonstrated reason why I&M’s Michigan customers would experience a substantially different
result; and Article 6 – I&M would expect treatment of operation and maintenance expenses and
obsolete equipment as previously described.

ABATE (0008): The quantifiable benefits to residential customers must outweigh the cost of
deployment before any utility proceeds with deployment of AMI and the investment is considered
for rate-base treatment for residential customers only. There should be no added incentives for
utilities other than a return on a return of the utilities’ reasonable and prudent investment.

Utility Workers Union of America (0009, 0010, 0011): According to a recent paper done for the
National Regulatory Research Institute (NRRI), AMI cost estimates range from as low as $100 per
meter to as high as $525 per meter, depending on (a) the type of meter, (b) the communications
network between the meter and the utility, (c) the meter data management system and (d) the
extent to which tariffs are changed and back-office software is changed to take advantage of AMI
functionalities. AMI is a major investment and clearly, this level of investment will require a
detailed analysis and evaluation of the costs and benefits of such proposals prior to requiring
customers to pay for these expensive new systems. It will be important for the Commission to
determine not only what AMI is and what it will cost, but what benefits are likely to ensue and
how to conduct the cost-benefit analysis that will contribute to an evaluation of any AMI proposal.
It is recommended that the Commission identify the cost and benefit components of any proposed
AMI system and establish the cost-benefit analysis that will be required to determine whether this
expensive investment will actually benefit customers. The case for AMI will typically identify two
primary needs for the AMI functionality: (1) Operational Cost Savings related to the ongoing
operations of the utility, most of which relate to the “regulated” distribution part of the utility’s
operations; and, (2) Generation Supply Savings, relating to the impact of potential demand
response programs designed to reduce usage or peak usage. The Commission should require the
utility to identify the scenarios it has identified and assessed for achieving these goals.
Specifically, the utility should be required to identify all the options considered to achieve the
same goals and objectives in both major cost categories. Utilities should be required to identify
their proposed benefits in a uniform manner and use a standardized cost benefit “test” as the means
to determine whether the benefits exceed the costs over a reasonable period of time.

Wisconsin Public Service (0012): Costs for AMI are mostly driven by residential and small
commercial customers. Past deployments of higher cost metering have been recovered from
industrial customers, future AMI costs should be assigned appropriately. Pilot projects should
precede full deployment and recovery of reasonable costs for pilots should be pre-approved by the Commission.

**DTE (0013):** Costs and benefits should be evaluated as part of normal rate case proceedings of each MI utility. The recovery process should contain provision to account for regulatory lag between rate cases, regulatory asset deferral for labor recovery and in lieu of AFUDC, a cash return on financing costs. Each utility should perform a thorough financial cost-benefit analysis on the incremental investment of AMI (pro forma modeling platform for business case development should be used). FERC contains a model for this. The Commission should encourage utilities with overlapping service territories to evaluate the feasibility of sharing a common network infrastructure (DTE should work with Wyandotte and Consumers in areas for DTE provides on gas and vice versa). Network sharing options should be evaluated from a cost/benefit, ongoing operations and technical feasibility perspective. Each utility is best suited to perform their own comprehensive assessment of their service territory and AMI technology needs.

**Elster (0014):** This utility is in support of a comprehensive assessment i.e. Total Resource Cost Test. There are two deployment approaches, pilot deployment or full scale deployment. For pilot deployments, the costs and benefits to utilities and customers are liberally addressed and this is how a utility determines if AMI will be appropriate for its customers (some or all customers). Full scale deployment is typically after pilots have been run; the utility commission is likely to have rules or regulation in place that address cost/benefit analysis. If the cost/benefit review is positive, then the rules typically can say that the utility may deploy and gain cost recovery in rates.

**Constellation (0015):** If customers are to become responsible for the cost of AMI they should be the beneficiaries of tariffs that accurately depict the underlying cost of the energy being consumed at any given time.

**Itron (0016):** The Commission should consider de-coupling the delivery cost from the energy cost and provide incentives to utilities, such as a higher rate of return on its assets in return for promoting ratepayers to be better stewards of this valuable commodity, as well as provide higher degree of reliability to the electric network they manage.

**Consumers (0017):** Deployment approaches need to be determined by the utilities to minimize any negative impact on customers and maximize the benefits that can be achieved. Issues such as meter reading practices and existing labor contracts and the potential for demand response and load control programs will affect how quickly benefits can be realized. Utilities should be afforded the flexibility to address cost recovery and customer benefits in general rate proceedings and/or AMI-specific cases. Pre-approval of AMI spending plans and related rates or surcharges in either a general rate case or AMI-specific proceeding would allow timely recovery of prudent costs.

**Trilliant (0020):** The commission should approve utility proposals that recognize benefits throughout the deployment and not based on the completion of the entire project. Current approaches use regions of meter routes that enable the switch to AMI by meter route and this should allow the utility to recognize the benefits and offer consumers benefits quickly within the deployment schedule.
Northern States Power (Xcel Energy) (0021): A format for evaluating the costs and benefits to utilities and rate payers should be agreed upon between the utilities and the Commission prior to evaluation. These costs and benefits should consider the evidence of ratepayer interest in Michigan of given features of the solution against realizations of utilities, and the prospective improvement to distribution line quality and service as a result of implementing the solution(s) being considered for an environment. Programs from states with previous implementation may be used as a reference to help determine this analysis.

Sensus (0022): This will require significant investment and should be supported by both substantiated business models and rate recovery.

Opsommer (0023 - revised 0005): Costs should be considered in a holistic manner spread out among consumers, but the potential for some costs to be borne on a specific consumer basic might be employed for certain advanced services.

6. The Commission is considering open-source, non-proprietary guidelines for advanced meters. Have these systems been successfully implemented elsewhere? If the Commission prescribes guidelines for open-source, non-proprietary systems, what should these guidelines say?

We Energies (0004): The concept of “open source” is probably not attainable in the AMI industry. It is unlikely that manufacturers are going to provide their software to other competitors under the open source concept. The MPSC guidelines should focus on which types of appliances should be controlled and with which network and the utility is responsible for making the communication work. They could communicate through potentially multiple routes such as the meter, wireless mesh network, power line carrier, broadband over power line, cell phone, etc.

Indiana Michigan Power (0006): I&M is not a proponent of using an open-source, non-proprietary methodology for AMI deployment because it has not been successfully utilized to date and may stifle rather than encourage future innovation. I&M is a proponent of standards that allow interoperability between meters, communication networks and back office systems. The company believes that these interoperability standards will allow the co-existence of multi-vendor systems.

ABATE (0008): No Comment due to lack of information.

Utility Workers Union of America (0009, 0010, 0011): No detailed information is available since it appears that no open-source and non-proprietary systems have been imposed or implemented.

Wisconsin Public Service (0012): WPSC/UPPCO is not aware of any utilities that have successfully implemented open-source, non-proprietary advanced metering systems. While WPSC believes such guidelines would be beneficial, it believes that no single state or utility can determine them. Utilities are working with AMI vendors to encourage development of open-source and standard protocol networks but the technology doesn’t currently exist and widely accepted standards are not in place.
**DTE (0013):** It would be imprudent at this time for the Commission to set standards on the meter and communication methods because open-source and non-proprietary systems have not been implemented in mass anywhere in the U.S. Uniform standards should be adopted by the industry, which could take many years, before fully interoperable systems are commercially available. Open-source guidelines should also ensure that network security is not compromised by open sharing of software source code.

**Elster (0014):** There is a distinction between “open” architecture and proprietary technology/services. While there may be standards, there is not a single end to end solution in the industry that is not proprietary in some manner. This utility tries to utilize standards where they exist and find ways to collaborate with competitors and partners. This utility is in support of “open” architecture. The national Energy Independence and Security Act of 2007 established a process to develop interoperability standards for “smart grid” products from the power plant to the end use application.

**Constellation (0015):** Same response as Question 2.

**Itron (0016):** Open architecture systems (non-proprietary) have worked well when the equipment industry and the consumers of the technology have worked together without any regulatory guidance. It has been demonstrated in the past that regulatory efforts to create open architecture have very limited success around the world. Itron strongly believes that the advanced metering industry in the U.S. is sound, robust, and mature and does not need any regulatory oversight in defining open architecture. Regarding any non-proprietary systems, Itron is in the process of implementing their open-source, standards based AMI system. Itron powers an open source website, where anyone can download open source code that Itron has developed.

**Consumers (0017):** We need to avoid the term “open source”. Adherence to open standards for data format and data communications will lead to better interoperability between different vendor’s devices and should provide cost benefits for utilities over the lifecycle of these systems. Open-source generally implies that human readable source code must be supplied with all applications distributed as open-source software. Open-source with its implications is not conducive to AMI system requirements, however, “open standards” will help assure that future customer owned devices within the home will be able to interface into the AMI networks. Due in part to the evolving nature of AMI systems and the utilities’ current large-scale investment in business applications, it is important not to limit selection of vendors by over emphasizing the importance of open standards. Open standards should be encouraged, however, many of the products available at this time still have some level of proprietary features. Each utility must have the ability to make decisions as to how best to interface AMI systems with current and possible future applications.

**Trilliant (0020):** Open source creates a challenge to the protection of the grid when utilities have to manage and control the data and functions. The Commission should provide guidelines on standards technology like ANSI C.12 standards and IEEE communication chip standards and should allow for multiple manufacturers to support the development of future solutions and ensure long term viability.
Northern States Power (Xcel Energy) (0021): Many of these systems are in the development stage with field trials being run. Though not totally completed and implemented it should be encouraged. Guidelines should point to specific standards for discrete interfaces while refraining from determining internal design, or specific technologies.

Sensus (0022): Most AMI providers claim to be “open”, however none are open the way that the LINUX software is open source. ANSI C12.22 allows registration of commonly accessible data pointers so that a vendor can not create product protection via secret features. Utilities should be able to choose the best technology to meet their demands. Also it should be required that the system is ANSI C12.22 compliant. There are licensed systems commercially available that are immune to many dangers.

Opsommer (0023 - revised 0005): Not addressed.

7. Should the Commission prescribe guidelines to deal with information transmission and storage issues? Should it require a pilot project or gradual deployment of advanced meters, in recognition of the volume of information that the market participants will have available from advanced meters?

We Energies (0004): Commission standards for information transmission and storage should be no more or less stringent than data acquired by any other means. The utility must use due diligence to protect their data system from outside intervention. Pilot projects of AMI make sense and allow the utility to test the system’s functionality at a small level before a large investment takes place.

Indiana Michigan Power (0006): Depending on the level of granularity required, the amount of AMI data collected will increase exponentially. Key issues which must be addressed include: (1) What data is to be collected? (2) How often is the data collected? (3) How often is the data transmitted to the utility’s central system? I&M urges the Commission to determine what each utility is envisioning since each utility’s unique infrastructure is an important consideration when establishing minimum functional standards. I&M’s gridSMART project envisions specific requirements for data collection and access to that data and the company believes there are sufficient pilots being conducted nationally that would give Michigan a general idea of the utility operations’ benefits and consumer impact from common AMI functions. I&M’s Michigan service territory is ideally suited to serve as a smart grid pilot for the State of Michigan. Further, I&M believes gradual deployments are recommended for purposes of understanding costs, benefits and impacts of AMI deployments before committing significant capital. AEP System experience has shown that most back office system changes take 6-12 months to implement - - gradual implementation allows the impact on systems to be evaluated and corrective action to be taken if necessary.

ABATE (0008): ABATE favors pilot programs but has a concern regarding the type of information management system that the utilities either have or will have to acquire and whether that information management system is scalable.
Utility Workers Union of America (0009, 0010, 0011): The Commission should carefully evaluate whether “market participants” should have access to the detailed usage and usage pattern information that will be produced as a result of the AMI systems and, if so, how such access will be allowed. At a minimum, customers should have the right to restrict access to their personal usage information unless they have provided explicit approval for such access to a specific provider.

Wisconsin Public Service (0012): It is not appropriate to prescribe guidelines for networks and head-end storage. Consumers and businesses should drive the need for more data and an effective Meter Data Management system will likely be required to support any AMI system with more than core capabilities. Utilities will drive the market to improve this as well as network and storage systems. A pilot cannot validate full system performance. The perception is that a possible future scenario could be one where the majority of rate payers, not willing to purchase in-home controls, could be paying for an expensive, under utilized and obsolete system demanded by a small customer segment interested in monitoring and controlling their energy usage on a daily basis.

DTE (0013): No, DTE does not believe this is necessary. It is the responsibility of MI utilities to ensure that information is stored and shared in a secure and accessible manner and customer data is confidential and proprietary. Utilities take extensive measures to protect the data and ensure customer consent before sharing any data or information with other parties. The Commission should not require specific pilots to solely demonstrate information management. Utilities should carefully consider the implications of managing large volumes of advanced metering data, and market guidelines are already in place for the storage and sharing of energy data across market participants. These guidelines follow strict code of conduct policies and provide the basis for daily business transactions by utilities.

Elster (0014): This utility believes that, at this time, recommending guidelines for addressing information transmission and storage issues may be premature. Regarding the storage issues, each utility may have specific capabilities or may want certain capabilities that differ from the neighboring utility. Regarding a pilot project or gradual deployment of advanced meters there is no recommendation at this time. Only to note that each utility has specific goals and objectives regarding the investment of advanced metering and will want to promote deployment in a way that best suits their circumstances.

Constellation (0015): Same response as Question 2.

Itron (0016): Information transmission and storage exchange will be adopted by the major market players wherever it is technologically smart and prudent without the need of any regulatory guidance. The market participants should prescribe the rules for transmission and storage issues. The AMI industry experience can be leveraged without the need for pilots.

Consumers (0017): Issues that deal with the transmission and storage of information are best handled by the internal architecture teams within the utilities based on existing infrastructure and potential for future integration. Each utility must determine mass deployment plans to best meet business operational and customer requirements.
**AARP (0018):** If a pilot program is conducted for any form of dynamic pricing for residential customers it should specifically include a representative sample of low income customers with usage that is lower than the residential class average. Any evaluation of the pilot program should identify the impacts of the program, and its results, on all residential customers of various usage and income levels, both in terms of costs, benefits, and bill payment impacts.

**Trilliant (0020):** Information and storage should be maintained by the utility and if the Commission desires access they should consider policies on access to the data using market technologies like Electronic Data Interchange and rules governing the access and timeliness of the data to approved parties. Open source creates a challenge to the protection of the grid when utilities have to manage and control the data and functions. The Commission should provide guidelines on standards technology like ANSI C.12 standards and IEEE communication chip standards and should allow for multiple manufacturers to support the development of future solutions and ensure long term viability.

**Northern States Power (Xcel Energy) (0021):** The Commission should provide a statement of agreement or dissent with each respective utility in each case relative to information transmission and storage issues. Prescribing guidelines on these issues prior to a request for recovery could result in antiquated guidelines and should be avoided since annual changes in IT back office capabilities are accompanied by different nominal and marginal changes in cost and efficiencies. The Commission should require a pilot project commensurate with available resources, utility costs, rate payer inconvenience, and impact on utility operations while exemplifying the benefits to the service area where the pilot project occurs.

**Sensus (0022):** An initial pilot is both standard practice and effective. The size and scope of the pilot should be significant enough to determine efficiencies and impact. Only a mass deployed system will allow the business model and legislation to have its true benefit and impact.

**Opsommer (0023 - revised 0005):** Not Addressed.

8. **To what degree is the security of AMI a concern, and what level of security should be designed in the system?**

**We Energies (0004):** Security of AMI must be addressed especially in the evolution of the smart grid. It is important to have the necessary security to prevent a hacker from tampering with the system equipment or altering meter read data.

**Indiana Michigan Power (0006):** Security requirements should match the criticality of the functions. Security requirements for meter reading are not as rigorous as those for remote service switch control and grid management functions are the highest security concern due to the vast scope of influence that a security breach could have on operation of the grid. I&M would encourage the MPSC to endorse smart grid security recommendations resulting from an industry consortium such as AMISec which sponsors the Utility Communication Architecture UtilityAMI Working Group.

**ABATE (0008):** No comment due to lack of information.
Utility Workers Union of America (0009, 0010, 0011): Considering the current exposure of computer security issues, the Commission should require the utility to demonstrate how it proposes to protect the usage and billing information associated with transmission of AMI data to and from the utility. Utility handling of customer usage data has been considered in telecommunications regulation, with the general result that customer proprietary network information (CPNI) obtained by the utility as a result of customers’ usage generally is to be protected from release to any third parties, and must not be released without consent, subpoena or warrant. Privacy implications from gathering customer real time electricity usage data are largely ignored and need to be addressed.

Wisconsin Public Service (0012): There needs to be security to prevent unauthorized access to data in the meter or network about other customers or to reprogram a meter’s functions. Unauthorized access to control of either in-home or distribution system equipment poses an even greater risk. Equipment manufacturers understand that data security is critical and should be required to demonstrate effective security, but not necessarily be required to use prescribed methods.

DTE (0013): Security should be of primary concern to utilities when selecting, implementing and operating AMI systems. Security reviews and periodic audits should be conducted by 3rd party security engineering firms to ensure a non-biased thorough review (an example is the Idaho National Laboratory (INL)). One of the most paramount security concerns or AMI is protecting against a threat agent gaining access to IT systems. Also the AMI-SEC, a national utility special interest group, has developed a comprehensive AMI infrastructure threat model along with several other documents advising on proper security approaches to an AMI solution.

Elster (0014): Currently there are specific NERC security standards that utilities are responsible for meeting. Some utilities have included their metering assets within those requirements. Each meter manufacturer and meter technology provider will likely want to build the security into their products individually; Elster’s standard offering provides a very high level of data security.

Constellation (0015): Same response as Question 2.

Itron (0016): It is critical to reassess FERC mandates along with corresponding NERC requirements regarding security. The standards bodies that define security standards relevant to AMI are essential including, FERC, NERC, NIST, ISO/IEC, AMI-SEC.

Consumers (0017): Yes, security is a significant concern. We are participating with a large group of national and international utilities, vendors, and government organizations that are currently working together to address the issues around security for AMI through the AMI-SEC Task Force. We expect to comply with the industry standards; however guidelines should allow pilots and testing to be conducted prior to full industry security standards being available.

Trilliant (0020): Security is an area that should be evaluated by the utility as part of the technology selection but not explicitly specified by the Commission.
Northern States Power (Xcel Energy) (0021): A number of AMI technologies exist, as there are a number of technological solutions available for delivering operational control and the AMI data. The extent to which the control operations and meter are secure and the extent to which access to the meter’s internal data is secure are all to be considered. The level of security should be consistent with industry standards and be consistent with the associated level of risk.

Sensus (0022): AMI security should be of similar nature as the controls systems for power generation plants which have very careful control of outside contact.

Opsommer (0023 - revised 0005): People could be able to profile homes determining when energy is used and figure out when people are home or away presenting a burglary hazard. AMI could interact with a home’s WI-FI network and it should be considered if AMI would be susceptible to viruses. A future terrorist attack could result in virtual blackout where power is available but a hacker shuts off the ability of a consumer to connect. It is also important how a person is notified that their power is going to be remotely shut off and it must be assured that wrong addresses are not shut off.

9. Are there other issues the Commission should address in this proceeding?

Gerald Leach (0003): (Did not follow question format but submitted general comments): Centralized remote management and control would be beneficial. It would probably make sense to develop a standards body comprised of all the electric metering players, IEEE, etc. One problem that could occur is that one vendor ends up applying the standards in a unique way that precludes other vendors from fully participating with deployed systems. It would be great to have multiple vendor products fully integrated into one system infrastructure, using the same data protocol and applications.

Elster ((0014), We Energies (0005), Itron (0016): No comments.

Indiana Michigan Power (0006) – I&M believes the Louisiana Public Service Commission’s Final Proposed Rule in Docket No. R-29213, Subdocket A is an excellent template for further consideration of minimum functionality standards and criteria. Proposed revisions to the template should include the following; removal of the disconnect activation switch at the meter (Section 3.6.4), removal of reference to ANSI C12.22 due to potential bias toward a particular vendor’s products (Section 3.6.9), reference to smart appliance technology should be prefaced with “if available” (Section 3.6.10), the 12-month MPSC approval period should be shortened to six months due to the rapid evolution of AMI technologies (Section 3.9), bi-annual reporting during the deployment period seems appropriate but annual monitoring reports for three years following full deployment are recommended. I&M would encourage the Commission to expand the AMI initiative to be more comprehensive and address all smart grid components under one umbrella. The following components should be added: (1) Common communication infrastructure, (2) Distribution grid managements, including distribution automation where possible and appropriate, (3) Distributed energy resources, (4) Plug-in hybrid electric vehicles, and (5) Consumer programs for energy efficiency and load control. Structural changes in electric service and rates are necessary to provide customers with the proper incentives that match future energy costs and risks. The traditional approach of making the flat rate structure the default option is not likely to produce the enrollment level required to make the necessary impact. Demand response programs should
become the default service offering, with an opt out provision to more traditional service and rate design. The shift may cause traditional flat rates to be higher than time-of-use rates that more accurately capture the costs to the utility and customers.

**Bill Emmerich: Freeing the Grid: (0007):** Bill Emmerich submitted a 115 page document “Freeing the Grid” regarding the benefits of net metering and renewable energy but not addressing specifically AMI.

**ABATE (0008):** The Commission should identify a discount rate to be used in any cost benefit analysis; gather information on the useful lives of the equipment and any software; and identify any new rate offerings that will allow residential customers to benefit from a change in their buying habits.

**Utility Workers Union of America (0009, 0010, 0011):** There are five core issues the Commission should address when considering any AMI proposal by a utility. The Commission should do the following (1) Address the definition it uses for AMI, (2) Recognize that AMI is a major investment, (3) Identify a cost-benefit analysis appropriate for AMI, (4) Carefully review the operational benefits associated with AMI, and (5) Review the utility’s proposed demand-response benefits relating to AMI and consider other potentially less costly demand response programs that do not require the expensive AMI investment to have similar results.

The Federal Energy Regulatory Commission (FERC) has stated its desire to promote and encourage demand response programs and the wider use of advanced meters. In promoting this view, FERC’s analysis assumes that wholesale spot market prices are a correct economic signal. If spot market prices are inflated due to strategic bidding, or are subject to manipulation, or for other reasons do not reflect incremental cost, as many contend, then the price signals for end use customers will be incorrect. Rather than focus on passing through “real time price signals” to residential customers based on short term or spot market prices, representatives of limited income and payment troubled customers should consider reforms being adopted in some states that are designed to ensure long term price stability and long term lowest price for essential electricity service. Advocates for such customer groups should ask for development of the least expensive demand response programs that are likely to benefit all customers and focus on closely linking the demand response programs with those specific customer usage profiles that are likely to contribute to the objectives of the program in the most cost effective manner. Typically, this would require an analysis of simpler direct load control programs that reward the participating customer for a modest level of interruption or appliance cycling and are typically not intended to “punish” lower usage customers with higher prices at peak usage periods. Additionally, any program that is aimed at residential customers in the form of a pilot program to test time-of-use or critical-peak-pricing options or rate designs should include identified low income customers with usage that is lower than average residential customers and analyze the impacts of such programs on those customers who do not or cannot take actions to avoid the higher prices.

On a related issue, demand response programs designed to reduce peak usage which claims the benefits of reducing greenhouse gas emissions should be carefully studied. Logic suggests that shifting more usage to off peak periods would require an increased reliance on baseload generating plants which are typically coal-fired and nuclear generation. Any claims of environmental benefit
should be carefully examined to determine whether most of the peak usage is just shifted to off-peak hours, thus limiting any environmental benefits associated with these programs.

As stated in the previously referenced NRRI Report: “Whenever a utility seeks to reflect costs in rates, not only must the benefits of the particular investment decision exceed the costs, but the choice must be the best among a reasonable set of options available to the utility for purpose(s) at the time.” The report goes on to state that, for utilities to make a case for AMI cost recovery, they will need to prepare information for the regulator demonstrating; (1) The need or needs for the functionalities provided by the investment; (2) The array of reasonable alternatives available, including the one chosen, for meeting the needs; (3) The costs of each alternative; (4) The benefits of each alternative; and (5) The relative costs and benefits of the alternatives compared. The Commission should identify the specific Cost Benefit “test” that it will rely on to evaluate an AMI proposal so that utility proposals can be fairly evaluated on an “apples to apples” basis.

Wisconsin Public Service (0012) – A comprehensive definition of AMI as it relates to these issues would be helpful. Expanding the discussion to include natural gas and water will bring new consideration into play and if the Commission intends to mandate advanced AMI functionality programs or rates, it should work proactively with utilities in forums such as this.

DTE (0013):
In response to the Louisiana PSC Docket R-29213 DTE responds:
- Section 3.2: Commission certification should not be required to any new pilot, partial or full scale deployment of AMI.
- Section 3.4: We agree with this approach for recovery through rates.
- Section 3.5.3 and 3.6: the requirement for one or more seems very broad and open to any combination of technologies or functions, commission should consider required and optional standards.
- Section 3.7: We agree with this for protection of customer data.
- Overall this order seems to be very liberal and allows for innovation by the utilities as technologies and features of AMI evolve.

Also, AMI costs should be carefully assessed against the benefits over the expected life of the technology, DTE recommends a project life of 20 years for the overall AMI investment. Utilities should be given an opportunity to demonstrate prudency of their investment through a review process similar to what has been used for other large capital projects. Since the time between rate cases, vary, regulatory lag needs to be minimized or curtailed via alternative recovery and deferral mechanisms.

Constellation (0015): A critical factor for AMI success in Michigan is the existence of utility tariffs that are post-restructuring, unbundled, and appropriately priced based upon the underlying cost of energy being consumed. An AMI program will not provide all of the associated benefits for consumers until Michigan’s utility tariffs have conformed to this pricing structure. Customer’s responses to price signals need to be real, not based on the illusion provided through average cost rates and PSCR mechanisms that mask the true cost of energy. Average cost rates with a dysfunctional PCR mechanism undermine the entire premise of this initiative.
Consumers (0017):

* Rate Structures
Once advanced metering capabilities are in place, rate structures must be developed and implemented that provide customers incentives to conserve energy and avoid usage during peak load periods.

* Treatment of partially depreciated metering assets being retired
With the installation of AMI, most or all of the existing metering assets of varying vintages will be retired. Many of these devices will not have been fully depreciated.

* Shared Infrastructure
Additional discussion is required regarding shared infrastructure. While it appears on the surface to provide some net benefits, there are a number of potential issues including legal, equipment compatibility, competitive bidding, contractual and operational impacts that require further investigation.

* Comments on Louisiana’s docket
A certificate is a good idea and important to ensure rate recovery prior to mass deployment. We recommend that all the details of the Louisiana program be carefully reviewed before adoption to ensure that the process will allow for timely decisions prior to mass deployment.

AARP (0018): did not follow a question answer format but just submitted an essay type response, summarized as follows:

- The Commission puts the “proverbial cart before the horse”, and fails to first address more fundamental questions regarding whether AMI is cost-effective for ratepayers and to determine the consumer protections that are necessary if a “smart grid” or AMI is implemented by a MI utility.
- AARP does not support system-wide investment in AMI without first conducting a cost benefit analysis and adopting appropriate consumer protections. These protections include ensuring that dynamic pricing is an option, not a mandate for ratepayers.
- Older people and other vulnerable populations can not easily shift usage to off-peak, lower cost periods without risking their health.
- Costs and benefits to ratepayers, including costs and benefits of dynamic pricing options must be examined.
- For each pricing option evaluate whether the option is appropriate for each customer class and sub-groups within each class, based on the ability of each group to safely shift usage to off peak, the impact on customer bills, and potential to reduce overall energy usage.
- AARP recommends an opt-in approach where customers indicate they want to participate as opposed to an opt-out which automatically includes them unless they specifically ask to be left out.
- The Commission should conduct consumer education programs informing customers of both the costs and benefits associated.
- In conclusion, AMI may reduce consumption for some users but it is not appropriate for all. An investigation of necessary consumer protections, are as important as an investigation of minimum functionality.

A key focus area for AMI should be a defined demand response program with standards that take into account rate programs, reduction targets and tools to enable consumer response to pricing.
signals. Research shows energy consumption reductions in the 20-50% range with demand response. *Trilliant (0020)*

**Northern States Power (Xcel Energy) (0021):** The Commission should carefully separate the functions and operations of a meter device from that of a meter-reading device. The various manufacturers of meters and meter-reading apparatus/technology are not yet to the point where they are compatible with one another. The extent to which an available meter and an available meter-reading technology can deliver all or some of the other’s capabilities needs to be proven to the Commission prior to acceptance as fact. Capabilities in the AMI industry and prospects for their availability should be defined by a vendor or the utility. Available capabilities need to be proven to the Commission and its Staff with real, observable criteria of operability at a utility and within the field environment, available communication network, and fiscal logic of the utility where those AMI capabilities are deployed. While input from Ratepayer and Vendors is important, it becomes imperative that any standards, functionality, technologies or protocols be vendor neutral, and industry standards should be encouraged.

**Sensus (0022):** Has 100 years experience providing meters and over 20 years experience with AMR/AMI. They welcome a meeting with the MSPC.

**Opsommer (0023 - revised 0005):** A business case must be made for AMI that shows that AMI will save utilities money and those savings will be passed to consumers in lower rates. Legislative support should be high for any program that demonstrates multiple levels of flexible consumer involvement.
**COMPANY/UTILITY REFERENCES:**

1. Gerald Leach: (0003)
2. **We Energies:** Wisconsin Electric Power d/b/a We Energies (0004)
3. **Indiana Michigan Power Company** (0006)
4. Bill Emmerich: Freeing the Grid: (0007)
5. **ABATE:** The Association of Businesses Advocating Tariff Equity “ABATE” (0008)
   (0024 address change)
6. Utility Workers 223: (0009, 0010, 0011)
7. (WPSC): Wisconsin Public Service Corporation and (UPPCO) (0012)
8. **DTE/Michigan Consolidated Gas Company** (0013)
9. Elster Integrated Solutions (0014)
10. Constellation (0015)
11. Itron (0016)
12. Consumers Energy (0017)
13. AARP (0018)
14. MECA (0019)
15. Trilliant (0020)
17. Sensus (0022)
18. Representative Opsommer (0005 original) (0023 correction)
In re: Commission examination of the public benefits of potentially adopting rules, new tariffs, and/or other regulatory mechanisms that would promote (or require) the use of wireless metering in Louisiana.

NOTICE OF FINAL PROPOSED RULE (CORRECTED)

Pursuant to the Energy Policy Act of 2005, the Louisiana Public Service Commission ("Commission" or "LPSC") opened Docket No. R-29213 and published notice of the rulemaking in the Commission's Official Bulletin dated December 2, 2005. During the course of that proceeding, interventions were filed by Marathon Oil Company; southwestern Electric Power Company; Hunt Technologies, Inc.; Louisiana Energy Users Group; Cleo Power, LLC; Entergy Louisiana, LLC; Entergy Gulf States, Inc.; Cellnet Technology, Inc.; Distribution Control Systems, Inc.; Wal-Mart Louisiana, LLC; and, Sam's East, Inc. This proceeding was published in the Commission's Official Bulletin dated January 13, 2006. During the course of the proceeding, the following entities filed interventions in this proceeding: Southwestern Electric Power Company; Baton Rouge Water Company; Ascension Water Company; Louisiana Water Company; French Settlement Water Company; Cleo Power, LLC; Sprint Nextel; Louisiana Energy Users Group; Entergy Louisiana, LLC; Entergy Gulf States, Inc.; Cellnet Technology, Inc.; Hunt Technologies, Inc.; Atmos Energy Corporation; Elster Electricity, LLC; Distribution Control Systems, Inc.; International Business Machines Corporation; Wal-Mart Louisiana, LLC; and, Sam's East, Inc. Docket Nos. R-29213 and R-29213 Subdocket A were not consolidated; however, this rule applies to both proceedings and is being filed into both dockets accordingly.

Commission Staff requested comments on April 10, 2006 for both Docket R-29213 and R-29213 Sub. A. Also, a technical conference was conducted on May 2, 2006. After considering the information, comments and presentations received, Commission Staff developed a draft proposed rule. On January 26, 2007, the Commission Staff issued a Notice of Draft Proposed Rule and Request for Comments. After extending the deadline for filing comments from February 16, 2007 to February 23, 2007, Commission Staff reviewed the comments submitted by various parties and developed a second draft proposed rule. Commission Staff issued a Notice of Second Draft Proposed Rule, Reply Comments of Commission Staff and
Request for Comments on March 22, 2007. Commission Staff, in this notice, summarized some of the comments received, highlighted the changes made to its initial draft proposed rule based on those comments, and sought comments on the second draft proposed rule. Additionally, Commission Staff gave the interveners an opportunity to respond to comments filed by other interveners. After reviewing the comments received pursuant to Commission Staff's notice of second proposed rule and request for comments, Commission Staff has developed this final proposed rule. This matter has been placed on the Agenda for the Commission's Business and Executive Session scheduled for May 1, 2007 for discussion and possible vote by the Commission. A Staff Report will also be filed into the record of this proceeding.

FINAL PROPOSED RULE
(CORRECTED)

***Typographical corrections have been made to sections 4.1.1 and 6.2.4. These are the only changes.****

1. Purpose: The purpose of this rule is to define the terms and conditions under which electric and/or combined electric and gas utilities can seek the recovery of costs associated with the implementation of new advanced metering and demand response programs, including the integration of existing advanced metering or demand response programs into such new programs. This rule addresses the issues required under Section 1252 of the Energy Policy Act of 2005 for advanced metering and demand response programs.

2. Definitions: For purposes of this rule, the following terms will have the following meanings:

2.1. Advanced meter: any new or appropriately retrofitted meter that functions as part of an advanced metering system. An advanced meter is capable of

2.1.1. measuring and recording customer consumption, demand, and other parameters, in time-differentiated registers, such as daily, hourly, or other periodic or time-of-use basis, where appropriate to enable particular customers to obtain direct benefits from demand response programs and/or incentive-based pricing;

2.1.2. daily or more frequently transmits data measurements to a central collection point; and,

2.1.3. permits communication of consumption information between electric customers and utilities on a basis that will permit the offering of dynamic and incentive-based pricing programs and ancillary services, where appropriate.

2.2. Advanced Metering System ("AMS"): a system, including the associated hardware, software, and communications systems, that collects time-differentiated energy usage
from advanced meters. The AMS collects, processes, and records the information, and makes the information available to customers and utilities.

2.3. Ancillary services: Those services defined in FERC Order 888 that include those services necessary to support the transmission of electricity from resources to loads while maintaining reliable operation of the transmission system.

2.4. Cost-effectiveness tests: commonly accepted tests designed to empirically evaluate the net benefits of advanced metering, demand-side management, load management, or other energy efficiency plans. These commonly accepted tests should include, but are not limited to, those that are defined in the California Energy Commission Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs. These cost-effectiveness tests can also include other reasonably accepted methodologies for evaluating demand response and/or advanced metering system net benefits.

2.5. Demand Response ("DR") Programs: those programs that use advanced metering systems, and are designed to create a change in customer usage in response to changes in the price of electricity over time, or to provide incentive payments designed to induce lower electric use at times needed for economic or reliability purposes. DR programs may include one or more of the following features:

2.5.1. Dynamic Pricing: retail pricing for electricity consumed that is reflective of the fact that the cost of power generation and market prices vary during different hours of the day and time of the year. Programs can include, but are not limited to, time-of-use pricing, critical peak pricing, and real time pricing options.

2.5.2. Incentive-Based Demand Response Pricing: pricing programs that pay participating customers to reduce their loads at times required by the utility for economic or reliability purposes.

2.5.3. Price Based Demand Response Pricing: pricing programs that give customers time-varying rates that reflect the value and cost of electricity in different time periods.

2.6. Pilot AMS or DR Program: any program of limited length and scope designed to gather additional information on current technology options, various pricing alternatives, and effectiveness of a new AMS or DR program or service offering as approved by the Commission.

3. Certification:

3.1. Deployment and use of advanced meters by an electric utility shall be on a voluntary basis unless otherwise ordered by the Commission. Development and implementation of any DR program is also voluntary unless otherwise ordered by the Commission.
3.2. Commission certification is required prior to any new pilot, partial, or full-scale AMS or DR program deployment.

3.3. A new AMS and/or DR program can be proposed on either a permanent or pilot program basis and can be developed on a full-scale (all customers or all customers within a given customer class) or partial basis (limited to a group of customers or customer classes).

3.4. Utilities will have the opportunity to recover through their approved rates and charges prudently-incurred advanced metering costs including those costs associated with the deployment of a new AMS, any associated pilot program implementation, and any related DR programs, upon certification by the Commission that the implementation of these plans is in the public interest.

3.5. The Commission will use the following guidelines in reviewing whether or not a new AMS and/or DR program is in the public interest:

3.5.1. The benefits associated with the plan are greater than their costs as determined by standard cost-effectiveness tests or other reasonably estimated net benefits analysis.

3.5.2. Proposed AMS or DR pilot programs should have clearly defined goals and evaluation criteria. The Commission may deviate from a strict cost-effectiveness requirement for a pilot program if the scope is limited and the pilot is reasonably expected to lead to informational benefits that could result in the development and implementation of a cost-effective program that could ultimately reduce utility costs and/or increase value-added customer service offerings.

3.5.3. The AMS plan includes one or more of the following functional/operational applications:

3.5.3.1. Revenue cycle services that may include opportunities to: reduce billing inaccuracies; facilitate customers’ internet-access of their usage information; reduce potential utility services theft; reduce periodic and off-cycle meter reading costs; and provide for call center issue validation and restoration verification.

3.5.3.2. Demand response management that includes the improvement of data collection and load research information for the development of time-based rates and other service offerings.

3.5.3.3. Distribution asset optimization that includes: the ability to perform asset life analytics; improve network design; improve network operations; and perform remote tasks such as service disconnection/reconnection.
3.5.4. The AMS program includes specific DR programs for those customers included in any advanced metering or AMS deployment to the extent that net benefits are shown to be obtainable through the application of such DR programs to particular customer classes, recognizing that there may be a phase-in period between the installation of the AMS and the DR program offering.

3.5.5. The AMS and any associated technology, hardware, or software has been successfully tested and installed with at least 500 advanced meters in North America, Australia, Asia, or Western Europe. Deviations from this standard should be limited to pilot or experimental program purposes and for less than 10,000 meters. Such exemptions will be considered by the Commission on a case-by-case basis.

3.5.6. Any other standard that the Commission deems important in proving that a program results in net benefits to customers including more difficult to quantify service and operational benefits.

3.6. An AMS shall have one or more of the following advanced system capabilities:

3.6.1. Automated or remote meter reading;

3.6.2. Two-way communications;

3.6.3. Support for dynamic or incentive pricing and ancillary services (where appropriate);

3.6.4. Remote disconnection and reconnection capabilities, with all disconnections and reconnections being performed by the electric utility; which may include, but is not limited to, activation of a switch on the outside cover of the meter to resume full electrical service.

3.6.5. The capability to provide customers with price signals to facilitate DR programs, response to load control events, or other incentive pricing.

3.6.6. The capability to monitor compliance with load management and DR programs, and the ability to provide information on whether the customer has complied with program requirements and the compensation, if any, to which they may be entitled for their participation in any incentive-based programs.

3.6.7. Recording, processing, and communicating interval consumption information with the capability of providing at a minimum, hourly interval data on a daily basis, with the ability to provide more frequent interval data as dictated by the customer's profile and need.
3.6.8. Storage of meter data should comply with nationally recognized non-proprietary standards such as those promulgated by the American National Standards Institute ("ANSI").

3.6.9. Communication between the meter and its head-end system shall be consistent with an open standards architecture such as ANSI C12.22.

3.6.10. Provide the information necessary and the technological ability that permits customers to pre-program response of individual appliances upon notification of demand response or load control events. The communication technology and standard would be provided through the AMS and DR program. The appliance requirements, which would include the installation and maintenance of equipment on the customers' side of the point of delivery, would be the responsibility of the participating customer unless otherwise provided by the utility through a specific program offering.

3.7. The utility is prohibited from transferring any customer-specific information from any AMS outside the customer-utility working relationship without prior Commission approval. Summary data for reporting purposes to governmental, regulatory, and industry groups in which individual customer data is clearly indivisible from the total would not apply to this restriction.

3.8. If the Commission certifies a utility's AMS, DR, or pilot program as being in the public interest, then the utility's decision to deploy advanced meters will be deemed prudent.

3.9. The Commission will act upon a utility's request for approval of any AMS or DR program within 12 months of the application date. The Commission may extend the schedule for good cause. If the evaluation period is extended, the utility will be allowed to reevaluate and resubmit any program costs or analyses upon notification to the Commission.

4. Filing Requirements for AMS, DR Programs, or Pilot Program Certification. Before implementing any AMS, DR, or pilot program, a utility subject to LPSC-jurisdiction will be required to file an application for approval of such program, which shall include the following:

4.1. A specific implementation or pilot proposal that shows that the proposed plan is in the public interest and has estimated benefits greater than estimated costs. Pilot programs must meet the standards outlined in Section 3.5.2.

4.2. Standard cost-effectiveness test results or any other analyses estimating the expected net benefits of the proposed plan.

4.3. Supporting documentation and assumptions to show the reasoning and methodology used in developing the estimates of net benefits provided in Section 4.2.
4.4. Estimates and supporting documentation for the costs of deploying the AMS or establishing a DR program.

4.5. Separate identification of the estimated costs associated with the integration of the AMS and/or DR program with legacy software systems and any other indirect costs from systems supporting the proposed AMS and/or DR program.

4.6. Any operational savings expected to be obtained during the time the AMS or DR programs are in place.

4.7. A proposed schedule including all major milestones associated with AMS deployment, DR, or pilot program implementation.

4.8. A deployment schedule, by total estimated number of customers/meters for the duration of the program.

4.9. A cost recovery proposal for all costs associated with the plan. This proposal should provide clear information on how new DR and/or AMS program costs (or pilot program costs) will be recovered in rates through either the utility's next scheduled rate case and/or a surcharge to customers' bills. The proposal should also clearly identify how DR and/or AMS program costs will be allocated within or between customer classes.

4.10. A listing of the additional service offerings that will be created by the proposed AMS deployment and a schedule of when these services will be available to ratepayers.

4.11. Identification of customers which have advanced meters with capabilities meeting or exceeding program goals, that are either excluded from the program or program costs; subject to the restrictions in 3.7.

4.12. Estimated participation rates for any DR services offered.

4.13. Identification of the technologies to be used in the proposed plan and supporting information that the systems are based upon proven technologies.

4.14. If the AMS and/or DR plan are offered on a pilot basis, the utility should clearly specify:

   4.14.1. the reasons for limiting the plan to a pilot.

   4.14.2. the goals of the pilot program.

   4.14.3. the scope of the pilot in terms of services offered and participants.

   4.14.4. anticipated operational and informational benefits to be gathered from the plan.

   4.14.5. deployment and evaluation period for the pilot and major pilot milestones.
4.14.6. estimated total costs of the pilot.

4.14.7. anticipated cost recovery method for the pilot program.

4.14.8. program goals needed to be met in order to move the proposal from a pilot basis to permanent implementation.

4.15. A detailed description of how information will be communicated between the utility and customer including any internet-based enabled systems.

4.16. Proposed tariffs for all new AMS or DR service offerings.

5. Monitoring Requirements for AMS Deployment:

5.1. Utilities will be required to make monitoring reports available on the progress of the deployment of its AMS system on at least a bi-annual basis. The Commission can require more or less frequent reporting requirements in its certification process at its discretion.

5.2. The bi-annual reports will include:

5.2.1. A comparison of the approved or most recently revised schedule to the actual schedule with a discussion of the progress made in reaching major project milestones and any schedule variances in terms of meeting the certified level of anticipated installations deployment.

5.2.2. A comparison of the approved or most recently revised costs to the actual costs with a discussion of any cost variances.

5.2.3. A discussion of any anticipated challenges or significant developments that may affect future deployment and any increases in costs or schedule delays that may be associated with such challenges or developments.

5.2.4. A forecast of costs to complete the AMS deployment or DR plan as originally proposed or as most recently revised.


6.1. Utilities will be allowed to recover their prudently incurred costs under a mechanism approved by the Commission in its Order approving the AMS and/or DR plan or pilot program.
6.2. Utilities will be permitted to recover the following, among other, prudently incurred costs associated with the full or partial deployment of an AMS and/or DR plan or pilot program:

6.2.1. Capital costs and a return on the investment at the utility's authorized rate of return.

6.2.2. Implementation, operating, marketing, and other expenses needed to deploy the approved program.

6.2.3. Depreciation for capital investments associated with meters and accompanying data transmission systems. These costs will be based on a depreciable life established by the Commission. The utility should submit supporting documentation related to the expected life of the meters and accompanying data transmission systems which support its requested depreciation.

6.2.4. Depreciation for capital costs for data management infrastructure and software. These costs will be based upon a depreciable life established by the Commission. The utility should submit supporting documentation related to the expected life of the data management infrastructure and software which support its requested depreciation.

6.2.5. Any additional costs associated with updating legacy systems or other direct or indirect costs supporting any new program.