ADVANCED METERING AND DEMAND RESPONSIVE INFRASTRUCTURE: A SUMMARY OF THE PIER / CEC REFERENCE DESIGN, RELATED RESEARCH AND KEY FINDINGS

DRAFT

CONSULTANT REPORT

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1 Acknowledgements

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Finally, we would like to thank all of the stakeholders, particularly the members of the OpenAMI task force, which we contacted during the course of the project for taking the time to answer our questions and providing valuable input and guidance.

2 Introduction

In support of PIER's control and communications integration (C^2I) initiative for encouraging the deployment of distributed energy resources (DER), EnerNex Corporation has completed three projects to set the stage for evaluating what research and development on system integration may be required to implement demand response (DR) and distributed generation (DG) in California.

- In the first project, EnerNex surveyed the literature in order to create a ***map of the work already underway***, compared against the requirements for DR and DG in California (http://www.californiademandresponse.com/CIEE-CEC-CCIProjectMapping.pdf). The mapping was presented as a matrix which could be used to highlight gaps and overlap.
- As a result of the perceived gaps inferred from the matrix, a second project was funded to develop a ***straw man reference design*** for DR information exchange (http://ciee.ucop.edu/dretd/ReferenceDesign.pdf). This project heavily leveraged the EPRI IntelliGrid Architecture project results (http://www.intelligrid.info/) which the CEC contributed to via its membership in the IntelliGrid Consortium (http://www.epri-intelligrid.com/). One purpose of this reference design was to present a rational methodology for implementing the advanced metering infrastructure (AMI) as conceptualized by DR OIR (Order to Institute Rulemaking) Working Group (WG3) participants. The straw man was completed and has received critical review from a group of industry advisors and the AMI stakeholder community.
- In anticipation of the review of the reference design by AMI (and other) stakeholders, PIER initiated an R&D demonstration process to evaluate the concept of promoting DR information exchange. This effort involved ***technology transfer*** within the Energy Commission, between it and the CPUC, and with other entities, through internal workshops and other presentations. EnerNex and PIER successfully implemented a public workshop in February of 2005 which presented the concepts of the reference design and the need for an advanced communications infrastructure that would enable advanced metering and demand responsive infrastructure.

One of the key recommendations of the reference design report was the formation of an industry group that would take the reference design report findings and begin working out the necessary details for actual system designs. This recommendation was implemented immediately following the February 2005 workshop in the form of the OpenAMI Task Force. OpenAMI was created under the IntelliGrid Working Group of the Utility Communications Architecture International Users Group (http://www.ucausersgroup.org/).

With the completion of this research, we have observed that the results can form the basis of a methodology that regulatory agencies can use to evaluate proposals for implementing AMI systems in California. Section 4 of this report provides a questionnaire-oriented approach to performing such an evaluation.

Using the checklist provided in this document will help regulators to determine if a specific AMI proposal meets three different sets of criteria:

- The requirements set forth in CPUC rulings
- The functional requirements identified by the WG3 Meter Functional Specification Subgroup
- The core design principles agreed to by the OpenAMI organization.

In addition, this evaluation also addresses suitability for the implementation of demand response functions within the AMI system.

This remainder of this document consists of several sections:

- A discussion of the “state of the art”: the concepts and principles that the industry thinks will take California into implementation of a successful AMI and DR program.
- The checklist itself.
- A flowchart for using the checklist.
- Critical issues to remember while using the checklist
- Appendices containing the reference documents that started the whole process.

3 State of the Art

This section summarizes the important conclusions made so far in PIER's research into advanced metering and demand response, as well as the key agreements made by the OpenAMI industry task force.

Reading this discussion will help to understand the purpose of the checklist questions in section 4, and the process which led to its development.

3.1 The Need for a Reference Design

A reference design is an abstract definition of the key parts and interfaces of a product or system. For instance, the telecommunications industry defined a reference design for a cell phone that identified a keypad, a display, battery, transmitter, receiver, antenna, speaker and microphone. Such a design can sometimes appear to be simplistic, but nevertheless can serve (as in the cellphone example) to guide the development of standards through many generations of technology.

In the AMI context, reference designs are meant to play a clarifying role between regulatory legal documents and the functional specifications from each IOU.

The purpose of the AMI reference design is not to pick a solution but to promote low costs, promote interoperability (not necessarily plug and play) and define a system that can adapt to inevitable changes in regulatory policy (e.g., different dynamic tariffs). No matter how diligent policy makers are, they won't get it right on day one. They will want and need to make adjustments in tariffs and programs. Since we are talking about dynamic rates, we need to have reference design requirements that allow evolutionary changes. The reference design shouldn't care whether the designs implemented have all the intelligence in the end device or in the network or have something in between. It needs to define (i.e., show how) the flexibility required to deal with evolutionary changes and interoperability can be achieved in all scenarios.

The AMI reference design must also be mindful of future applications that affect an AMI implementation. Examples of these applications include under-voltage detection, under-frequency detection (if the sensors are available) and net metering. If a reference design is too rigid or short sighted, it may not be able to accommodate such applications. This would defeat the purpose of an intelligent architecture and reference design which is to allow for incremental, evolutionary change in both detail (e.g. tariffs), and applications.

3.2 Premise for the Draft Reference Design

The draft reference design developed for PIER identified a key, four point premise that still drives the reference design development process:

1. Demand Response (DR) will become a major resource to deal with California's future electricity problems,
2. An advanced metering infrastructure will be deployed on a large scale throughout the state,

3. Price signals and emergency signals will be used to induce load response when market imbalances and network contingencies exist, respectively
4. Technology will act as a proxy for end users.

3.3 Assumptions of the Draft Reference Design

If this four-part premise is true, then information exchange will be required between several organizations and systems and numerous applications that create and consume information will exist. This leads to the need to develop a conceptual model that will describe the information flows necessary to support demand response applications related applications.

These observations led to the identification of several key assumptions upon which the draft reference design prepared for PIER was based:

1. A reference design is needed for deploying the physical (hardware and software) infrastructure to support dynamic pricing and its related (connected) energy delivery (electricity, gas, water) information systems.
2. There will always be legacy systems coexisting with new products/technology and there will always be change.
3. Innovation (cheaper, better, faster) often comes bundled in proprietary packaging that protects investments in intellectual property development.
4. Ultimately, we want interoperable information systems but not necessarily "plug and play"; secure and open data/information exchange but not fixed communications protocols (physical and procedural); and standards that respond to design but do not exist for their own sake.
5. A reference design for DR and other electricity industry applications can be developed from other existing successful interoperable data/information exchange models (e.g., credit card information gathered at point-of-sale, computers and distributed to banks for invoicing; file exchange between PCs, Macs, Linux servers; etc.) which means an information exchange reference design can be achieved quickly and at shared cost.
6. It is extremely unlikely that the traditional standards process will provide a solution in time to facilitate the imminent rollout of widespread demand response infrastructure. Industry groups such as the UCA International Users Group and consortia such as EPRI's IntelliGrid Consortium can be much more effective in gathering the human and financial resources necessary to address the technical details of implementing solutions quickly before handing the work off to standards organizations.

In addition to these specific assumptions, there is an implied assumption that there is a business case to be made for demand response and a reference design.

3.4 The OpenAMI Mission Statement

Item 6 in the list described in section 3.3 was addressed through the creation of the OpenAMI (http://www.openami.org/) industry group. The OpenAMI mission statement and objectives are as follows:

Mission Statement

Foster enhanced functionality, lower costs and rapid customer adoption of Advanced Metering networks and Demand Response solutions through the development of a recommended open, standards-based information/data model, reference design and interoperability guidelines

Objectives

- Facilitate the broad adoption of advanced metering and demand response
- Define what 'open standards' means for advanced metering and demand response
- Diminish technical and functional risk concerns for utilities, regulators and rate-payers
- Empower consumers with tools to better understand and manage their energy use
- Foster industry innovation, efficiency and lower cost solutions

Since its formation, the OpenAMI Task Force has been developing a framework to facilitate a comprehensive reference design for advanced metering infrastructure with support for demand response.

3.5 The OpenAMI Principles

The OpenAMI task force has evaluated the draft reference design report and has embraced and adopted many of its principles. Key among these, in addition to the elements mentioned above, are the following principles:

- **Shareability**: Infrastructure's utilization of shared resources which offer economies of scale, minimize duplicative efforts, and if appropriately organized encourage the introduction of competing innovative solutions.
- **Ubiquity**: Users can readily take advantage of the infrastructure and what it provides.
- **Integrity**: The infrastructure operates at a high level of availability, performance and reliability.
- **Ease of use**: There are logical and consistent (preferably intuitive) rules and procedures for the infrastructure's use and management.
- **Cost effectiveness**: The value provided is consistent with capital and operational cost.
- **Standards**: The elements of the infrastructure and the ways in which they interrelate are clearly defined, published, useful, open and stable over time.
- **Openness:** The infrastructure is available to all qualified entities on a nondiscriminatory basis.

- **Security**: The infrastructure is protected against unauthorized access, interference with normal operation; it consistently implements information privacy and other security policies.

The OpenAMI group formally voted to adopt these principles and approve their use for the purpose of evaluating AMI systems. These principles form the basic of a formal evaluation questionnaire that will facilitate regulatory agency evaluation of AMI proposals. This evaluation approach and questionnaire is found in sections 4, 5 and 6.

3.6 The OpenAMI Interfaces and Domains

Another significant accomplishment of the OpenAMI task force was the agreement on a high-level set of interfaces and application domains for advanced metering and demand responsive infrastructure. This set of domains and interfaces is depicted in Figure 1 . It is important to note however, that such an architecture does not appear overnight. The key to any successful large system implementation is to take an evolutionary approach, as discussed in section 3.8.

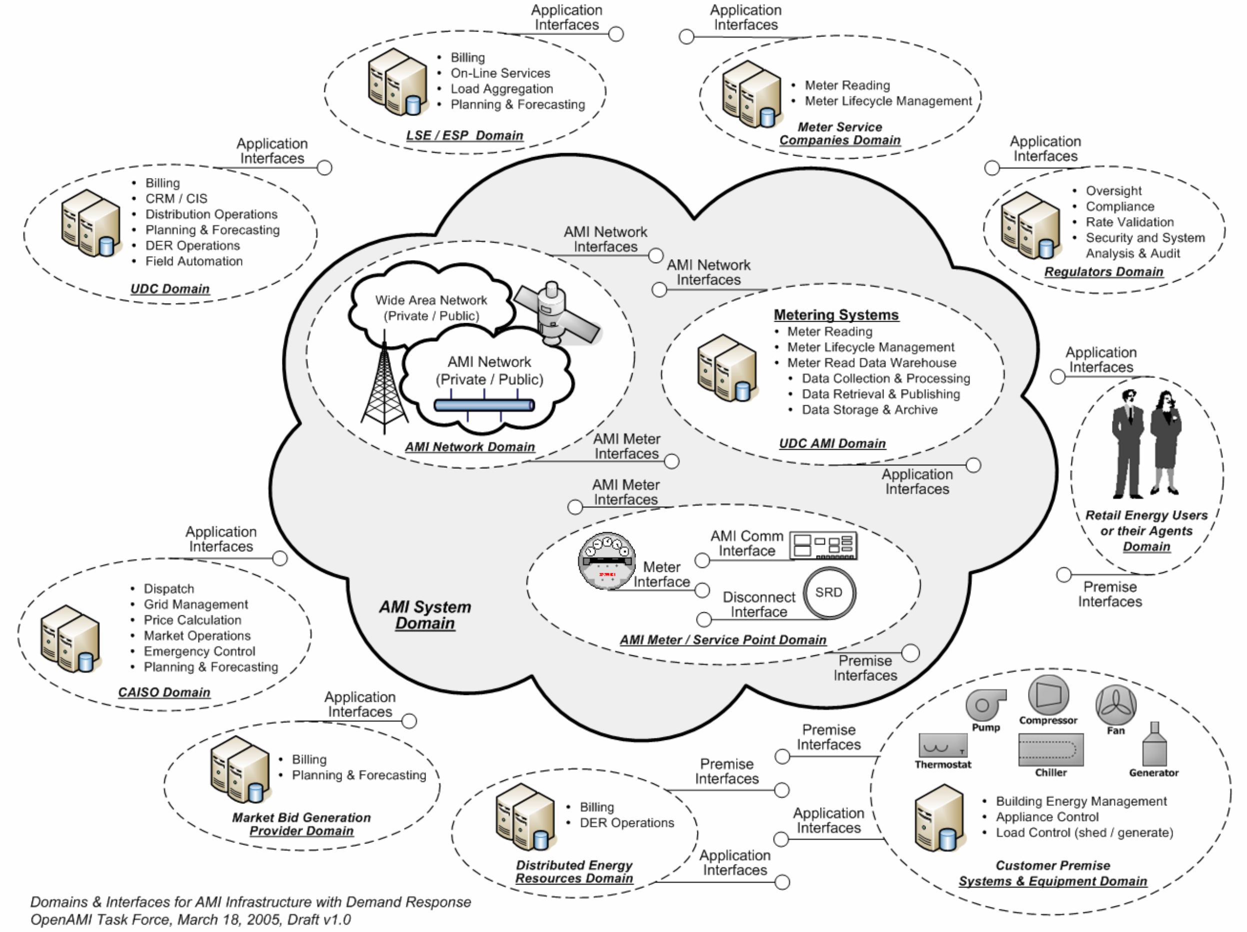


Figure 1 Domains and Interfaces for Advanced Metering Infrastructure with Demand Response

3.7 Independence from Specific Technologies

A key premise in any advanced reference design and system architecture is to ensure as much independence from underlying implementation technologies as possible. This principle can be understood by looking at the example of the personal computer reference design originally developed by IBM in the 1980's. This reference design resulted in a system that had a keyboard, monitor, pointing device, serial and parallel ports, memory, a processor, and mass storage device. Even though the details of the technologies that underlie these core elements have all undergone massive change and improvement over the past 25 years, the basic form, function, key interfaces and interrelationships between the components remains the same. This is the sign of a successful reference design.

In the AMI world, an example of a successful reference design would be one where a function such as the implementation of a tariff change could be independent of a centralized or decentralized network topology as shown in Figure 2 and Figure 3.

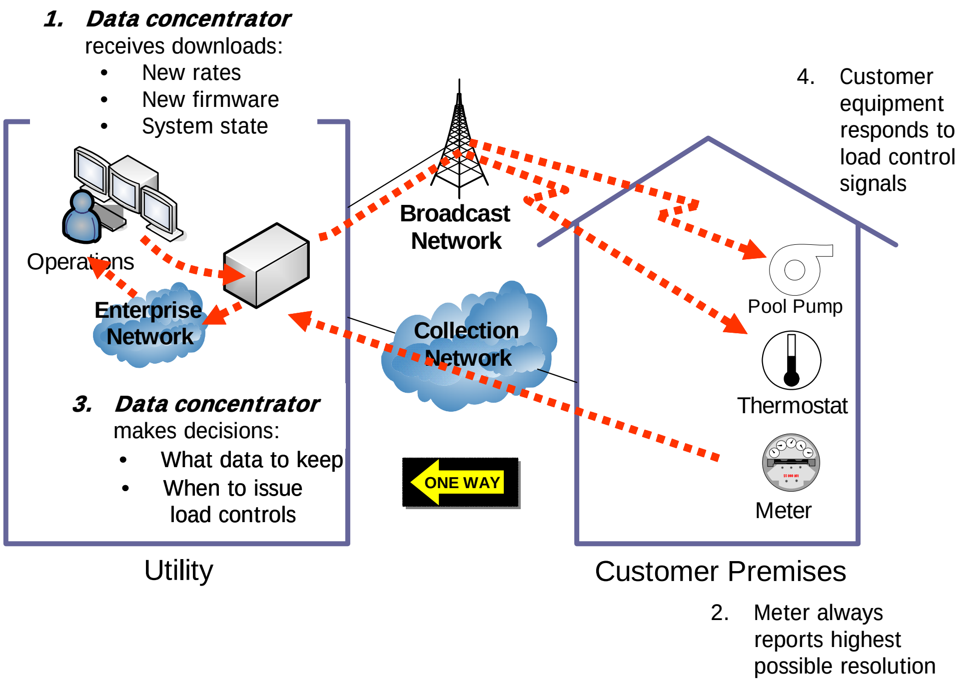


Figure 2 Centralized Implementation Example

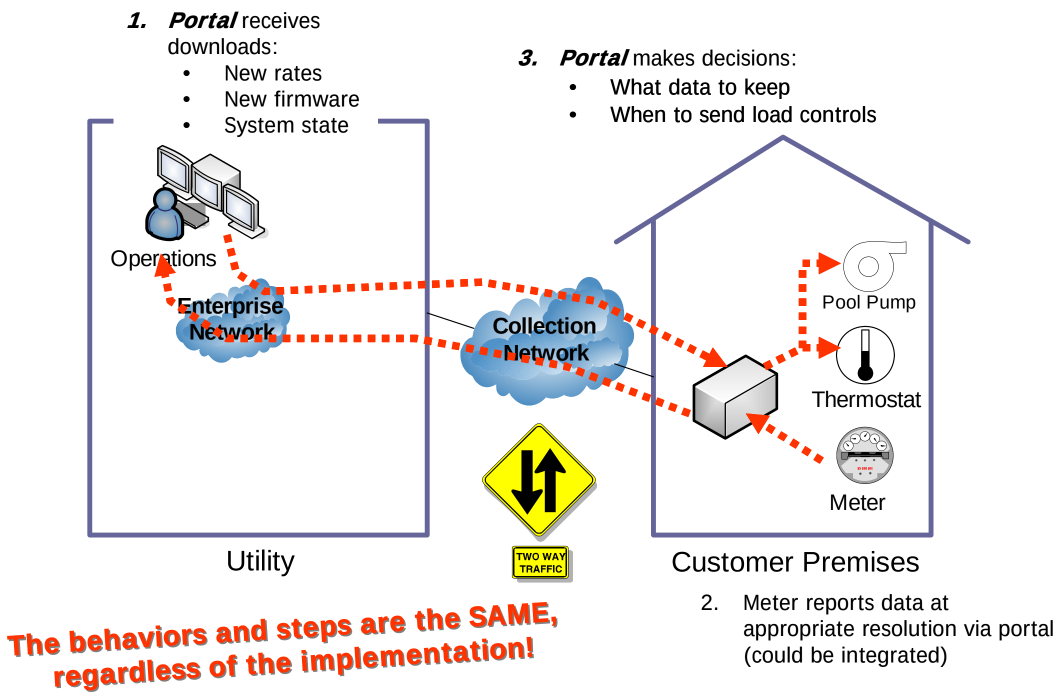


Figure 3 De-centralized Implementation Example

The EPRI IntelliGrid Architecture effort determined that technology independence is best implemented through the application of information modeling techniques that identify and describe in an abstract fashion the actors (individuals, organizations, equipment, systems) involved in information transfer, the data objects that the actors must exchange, and the points in the overall system where those exchanges must occur (interfaces). These concepts are illustrated in Figure 4.

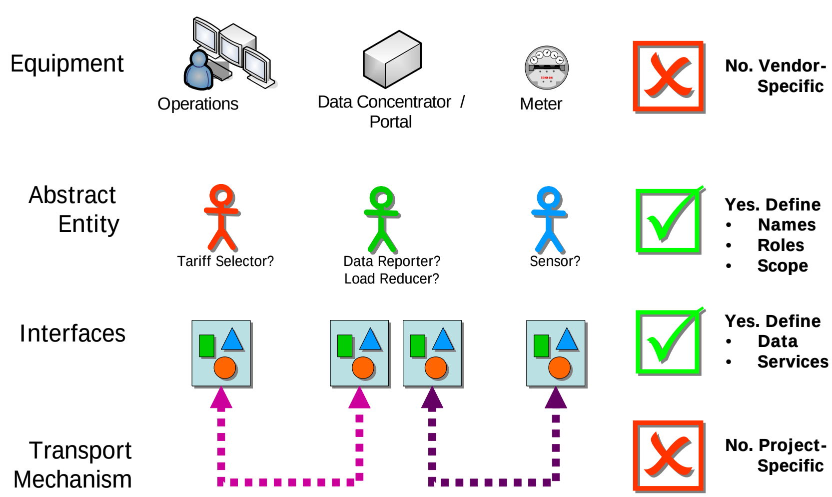


Figure 4 Abstract Objects and Interfaces Provide Technology Independence

3.8 Evolution to Open Systems

The diagram in Figure 1 was developed by the OpenAMI task force to capture the possible players, or “domains” involved in the use and operation of an automatic metering system. Not every project, nor every scenario, will necessarily involve all the domains shown here. However, these are the key devices, systems, people and organizations that have been identified by the task force members as playing a part.

The interfaces between the domains are identified with the circle-and-line “connector” symbol. These are the key data exchange mechanisms that the OpenAMI task force will eventually need to define.

Note that the “cloud” in the center of the diagram is intended to describe the AMI System itself: the participant in each scenario that exists for the express purpose of gathering, storing and reporting metering data. Other functions, such as billing, customer service, tariff definition, regulatory compliance verification, forecasting, market operations, etc. are considered out of its scope and are performed by other domains.

When discussing the evolution of AMI, it helps to simplify this view. For the moment, let’s consider just the following actors/domains:

- The AMI System
- The Independent System Operator (ISO)
- The Regulators of the power system
- The Independently Owned Utilities (IOUs) or Energy Service Providers (ESPs), which for the purposes of AMI perform basically the same functions.

The consumer is of course a key player in any AMI discussion, as are the other domains. However, the domains shown here can serve to represent most of the others in our simplified view.

This discussion will present the evolution of the metering infrastructure in four stages.

3.8.1 Stage 1: Multiple Systems, Multiple Users

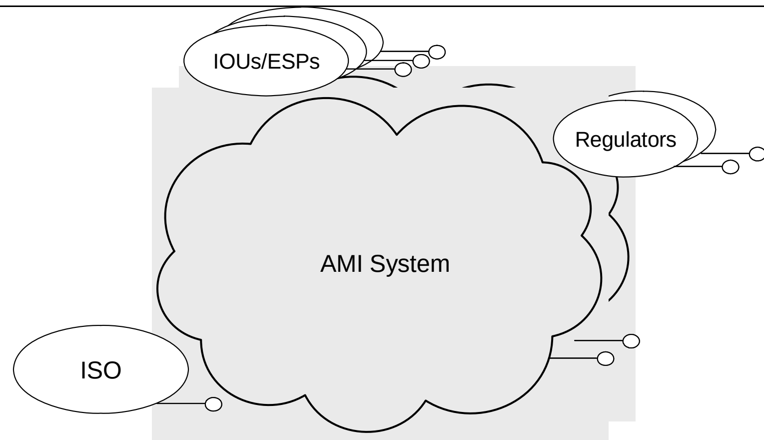
The first stage is to address the need to support multiple AMI systems and multiple users of these systems. Currently in the industry, AMI systems are typically deployed in a manner that intentionally limits their scope:

- They are deployed by a single vendor
- They communicate with a single utility and only to particular entities (e.g. billing) within those utilities.
- They use proprietary technologies

As a minimum level of interoperability, at least the first two of these limitations must be removed. In California, at least three IOUs (Southern California Edison, Pacific Gas and Electric, and San Diego Gas and Electric), the California ISO, and two regulators, the California

Energy Commission (CEC) and the California Public Utilities Commission (CPUC), must have access to the AMI data. In addition, it is a requirement that multiple AMI vendors be able to co-exist simultaneously and provide data to these clients.

For the first stage of interoperability, it is acceptable that AMI systems may use proprietary technologies within the AMI system boundaries. However, to ensure interoperability, interfaces between the domains must adhere to open standards. This first stage of interoperability is illustrated in Figure 5.

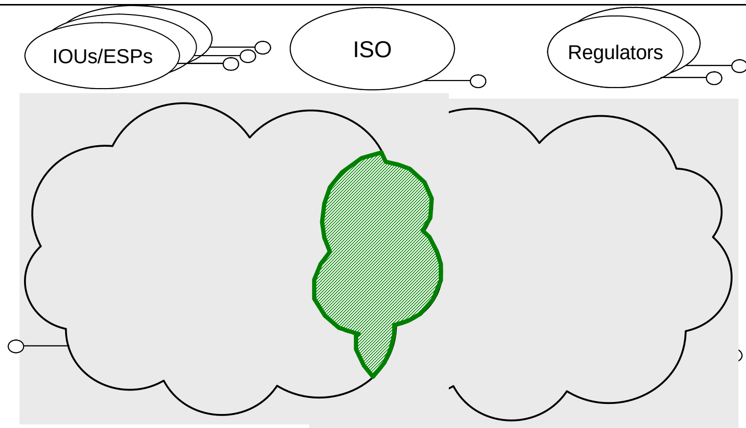


- Minimum level of interoperability
- Three IOUs, ISO and at least two regulators
- Multiple AMI vendors
- Systems can be proprietary within the domain and AMI System boundaries
- Standard interfaces between domains

Figure 5 – Stage 1: Multiple Systems, Multiple Users

3.8.2 Stage 2: Geographical Overlap

The second stage of interoperability is to permit multiple vendors' AMI systems to co-exist and overlap geographically. Let's reorganize the diagram somewhat to illustrate the relationship between multiple AMI systems. Figure 6 shows the "clients" of the AMI system on top, with two AMI systems provided by separate vendors side-by-side.



- Standard interfaces to IOUs, ISO and Regulators
- Still using proprietary interfaces to customer site
- Aggregation of data from multiple vendors
- Agreement between vendors that the technologies chosen will NOT prevent overlap
  - e.g. interfering radio frequencies
- Security and other principles applied within each proprietary "cloud"

Figure 6 - Stage 2: Geographical Overlap

For example, a given IOU may decide to use three different AMI systems, from different vendors, within its geographic territory:

- One for dense urban areas,
- One for specialty loads,
- One for sparse rural areas.

These three vendors would share a common, open standard interface to the IOU, which would likely aggregate the data and provide it via an open standard interface to the other client domains.

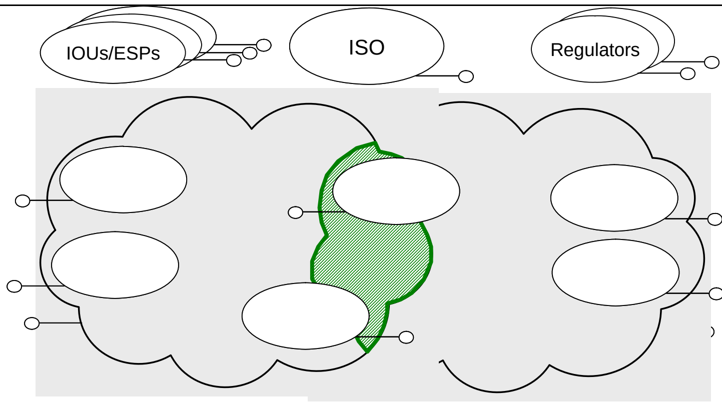
Within each AMI system, the vendor would likely still use a proprietary technology to access the customer site. However, there would be agreement between vendors that these technologies would not prevent physical overlap of their geographical areas. For instance, it is conceivable that one vendor could choose a set of radio frequencies or a transmission technology that would inadvertently interfere with, or "jam" the technologies of its competitors. Such interference would be specifically prevented in stage two, by agreement, in order to permit physical penetration of one vendors' area by other vendors. This would permit fair and open competition between vendors in neighboring geographic territories.

Another consequence of permitting geographical overlap would be a vital need for communications security, so that consumers' rights and vendors' financial interests would be protected even though AMI Systems would physically penetrate each other. For this reason, in Stage Two, the OpenAMI task force would need to identify which of its guiding principles must be adhered to within the AMI System domain, and which must be adhered to outside the AMI

System domain. One possibility would to have security, integrity, and cost effectiveness applied within each AMI System, while shareability, ubiquity, ease of use, standards and openness need only apply outside each "cloud" at this stage. This must be agreed by the OpenAMI participants from the industry.

3.8.3 Stage 3: Opening Internal Interfaces

The third stage of interoperability (shown in Figure 7) would occur when the industry begins to open some internal interfaces within each AMI System.   Doing so would permit IOUs to upgrade the automatic metering system by asking for bids on selected subsystems and sets of devices from vendors other than those currently providing the service.



- Upgrading the system in the future
- Internals of the systems become "visible" externally
- As new internal interfaces standardized, networks begin to "penetrate" each other
- Clients not "held hostage" by the initial owners of the domain
- Proprietary "clouds" begin to shrink

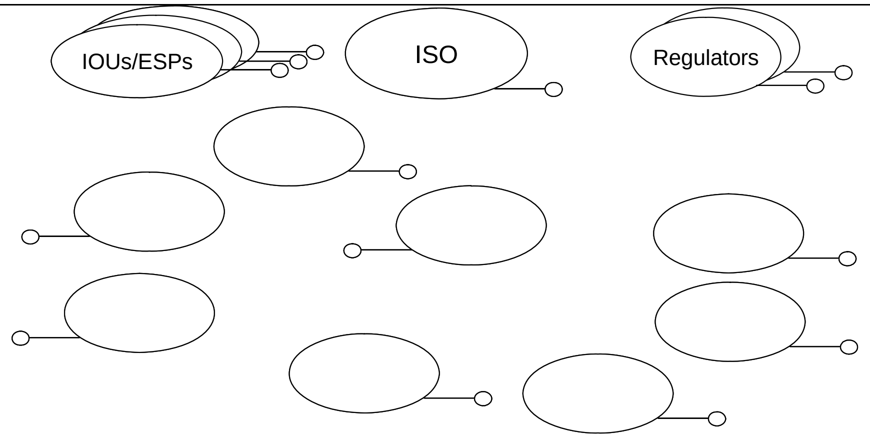
Figure 7 – Stage 3: Opening Internal Interfaces

The OpenAMI task force would define standards for some of the internal interfaces within each AMI System "cloud", permitting networks from different vendors to technologically as well as physically penetrate each other. Clients could now access data from multiple sources within each AMI system directly, without being restricted to a single point of contact. Vendors' systems would begin to communicate with each other to avoid conflicts and manage consumers requests, for instance to switch energy providers, or to report trouble.

By stage three, a given IOU will therefore no longer be "held hostage" to a particular vendor, simply because that vendor was the first one to operate in a particular territory. The proprietary AMI System "clouds" will begin to shrink and disappear.

3.8.4 Stage 4: Open Participation

The final stage of interoperability is to make automatic metering networks transparent to each other and invite open participation. This stage is illustrated in Figure 8and more completely in Figure 1 where we started. Once the physical and logical boundaries of AMI Systems become less important, new vendors will be able to join and compete for upgrades to the system.



- Networks become transparent to each other
- Boundaries become less important
- New vendors able to join
- System becomes fully interoperable and cost-effective

Figure 8 - Stage 4: Open Participation

The overall revenues of most vendors will increase because the size of the market that each vendor can feasibly access will increase radically. Simultaneously, installation and operating costs for the IOUs and their consumers will drop due to economies of scale and competition between vendors.

The resulting fully-interoperable system (Figure 1 on page 9) will encourage innovation and flexibility, and will be able to be upgraded in the future without excessive capital costs, finally becoming cost-effective on a large scale.

4 Evaluation Checklist

This section contains a checklist for regulators to evaluate AMI proposals. This checklist is organized based on the eight design principles agreed on by the OpenAMI task force.

It is not mandatory that all systems answer "Yes" to all questions on the checklist. However, better systems will be able to provide more "Yes" answers than poorer systems. It is assumed that the information necessary to answer these questions can be obtained directly from within the AMI proposal or by forwarding the questions on to the submitter who would respond and indicate where in the proposal each issue is addressed in more detail.

In the discussions that follow, a "consumer" is given to mean either an individual consumer or an agent representing multiple consumers.

4.1 Shareability

The infrastructure uses shared resources which offer economies of scale, minimize duplicative efforts, and if appropriately organized, encourage the introduction of competing innovative solutions.

4.1.1 Is at least the following information available to all authorized users?

a) Energy usage for each consumer?	Y ☐	N ☐
b) Energy costs for each consumer over each metering interval?	Y ☐	N ☐
c) Aggregated energy usage for large numbers of consumers?	Y ☐	N ☐
d) Audit trails of changes to tariffs, configuration, software and firmware?	Y ☐	N ☐
e) Audit trails of failures in the system?	Y ☐	N ☐

4.1.2 Is the information from the system available to each of the following users, simultaneously, if authorized?

a) The designated billing system?	Y ☐	N ☐
b) Auditors and regulators?	Y ☐	N ☐
c) Rate analysis and design systems?	Y ☐	N ☐
d) Energy management and control systems?	Y ☐	N ☐

e) Distribution management and control systems?	Y ☐	N ☐
f) Load management systems?	Y ☐	N ☐
g) Utility network engineers, planners and forecasters?	Y ☐	N ☐
h) Meter service companies?	Y ☐	N ☐
i) Outage management systems?	Y ☐	N ☐
j) Complaint resolution systems?	Y ☐	N ☐
k) The System Operator (e.g. CAISO)?	Y ☐	N ☐
l) Distributed generation providers?	Y ☐	N ☐
m) Customer service representatives?	Y ☐	N ☐
n) Retail consumer portal devices?	Y ☐	N ☐

4.1.3 Does the system use a communications network that is already in place, e.g. Cable, DSL, Cellular, other utilities?	Y ☐	N ☐

4.2 Ubiquity

Users can readily take advantage of the infrastructure and what it provides.

4.2.1 Can *all* consumers (residential, agricultural, commercial and industrial) within the service territory do the following?

a) Be connected to the system?	Y ☐	N ☐
b) Be notified of tariff changes, including critical peak pricing?	Y ☐	N ☐
c) Access their energy usage and cost information?	Y ☐	N ☐
d) Receive load control signals?	Y ☐	N ☐

4.2.2 If there are consumers who are not served by the system, are these exceptions due *only* to truly extreme physical, geographic or economic conditions?	Y ☐	N ☐

4.2.3	Will the system permit selected consumers to provide generation, i.e. be able to perform “net metering”?	Y ☐ N ☐
4.2.4	Can the system use different technologies to reach different consumers?	Y ☐ N ☐

4.3 Integrity

The infrastructure operates at a high level of availability, performance and reliability.

4.3.1	Does the system have published targets for availability, performance and reliability?	Y ☐ N ☐
4.3.2	Does the system meet its published targets for availability, performance and reliability?	Y ☐ N ☐
4.3.3	Can all equipment in the system continue operation during a power failure?	Y ☐ N ☐
4.3.4	Is there more than one communications path to every consumer site?	Y ☐ N ☐
4.3.5	Can all meters in the system be read within six hours?	Y ☐ N ☐
4.3.6	Can data from every consumer meter be recorded in at 1-hour intervals?	Y ☐ N ☐
4.3.7	Can data from selected consumers be recorded at 15-minute intervals?	Y ☐ N ☐
4.3.8	Is there provision for selected meters to be recorded at intervals smaller than 15 minutes?	Y ☐ N ☐
4.3.9	Is an Energy Service Provider automatically notified when a regulator makes a tariff change?	Y ☐ N ☐
4.3.10	Is a consumer automatically notified when a tariff change is offered?	Y ☐ N ☐
4.3.11	Can all consumers be notified of a critical peak within a day prior to the peak?	Y ☐ N ☐
4.3.12	Can selected consumers be notified of a critical peak within an hour of the peak?	Y ☐ N ☐

4.3.13 Can the Energy Service Provider be *certain* that all consumers have received notice of an upcoming tariff change or critical peak, sufficiently prior to the event?	Y ☐ N ☐

4.4 Ease of use

There are logical and consistent (preferably intuitive) rules and procedures for the infrastructure's use and management.

4.4.1	Can a consumer participate in a demand response program without having to actively respond to each tariff change?	Y ☐ N ☐
4.4.2	Can a consumer view their energy use for the previous day?	Y ☐ N ☐
4.4.3	Can a consumer view their energy cost for the previous day?	Y ☐ N ☐
4.4.4	Can selected customers be upgraded to see their energy usage and cost data on a more frequent basis, e.g. hourly?	Y ☐ N ☐
4.4.5	Is it clear from the information available to the consumer what impact their energy usage has on their energy costs (for instance, can they see a daily load curve or similar tool)?	Y ☐ N ☐
4.4.6	Can a consumer tell when a critical peak price is in effect?	Y ☐ N ☐
4.4.7	Can a consumer tell what level of tariff is in effect at any time?	Y ☐ N ☐
4.4.8	Can a consumer use multiple methods to learn about tariff choices, energy usage and cost (e.g. phone, internet, newspaper, local display)?	Y ☐ N ☐

4.4.9	Can any piece of equipment (e.g. meter, data concentrator, networking device) in the system be managed as follows from a central location?

a)	Enable/disable the device?	Y ☐ N ☐
b)	Change its logical address?	Y ☐ N ☐
c)	Download software or firmware?	Y ☐ N ☐

	d) Download new configuration?	Y ☐ N ☐
	e) Download new security parameters or credentials?	Y ☐ N ☐
	f) Gather operational statistics?	Y ☐ N ☐
	g) Receive spontaneous alarm reports for serious failure conditions?	Y ☐ N ☐

4.4.10	Can thousands of devices within the system be managed (i.e. enabled/ disabled/ downloaded) with a single command from a central location?	Y ☐ N ☐
4.4.11	Can selected consumers connect automated building management systems to the network using open, published standards?	Y ☐ N ☐

4.5 Cost effectiveness

The value provided is consistent with capital and operational cost.

4.5.1	Can the system be deployed to millions of consumer sites economically?	Y ☐ N ☐
4.5.2	Can the following information be changed without any visits to consumer sites?	Y ☐ N ☐
	a) The selection of a tariff?	Y ☐ N ☐
	b) The definition of tariffs (including selection of flat rate vs. CPP event vs. periodic, number of periods, start and stop time for each period, and rate for each period)?	Y ☐ N ☐
	c) The software or firmware for all equipment in the system?	Y ☐ N ☐
	d) Security parameters, credentials, and algorithms for all equipment?	Y ☐ N ☐
	e) The frequency of formal billing for each consumer?	Y ☐ N ☐
	f) The frequency of access to energy usage and cost information for each consumer?	Y ☐ N ☐
	g) The selection of a data recording interval?	Y ☐ N ☐

4.5.3 Can any selected portion of the system be upgraded to use a different communications network ….		
	a) Without changing consumer equipment?	Y ☐ N ☐
	b) Without visiting consumer sites?	Y ☐ N ☐
	c) Without requiring software or firmware changes?	Y ☐ N ☐

4.5.4 Can older equipment be upgraded with equipment from different vendors without changing the rest of the system?	Y ☐ N ☐
4.5.5 Can different collection rates and technologies be applied in different parts of the system to make collection of data more cost-effective?	Y ☐ N ☐
4.5.6 Can the system be easily scaled up *or down* based on consumer participation levels?	Y ☐ N ☐
4.5.7 Can new functionality such as detection of energy theft and diversion or outage detection, be added?	Y ☐ N ☐
a) Without changing consumer equipment?	Y ☐ N ☐
b) Without visiting consumer sites?	Y ☐ N ☐
c) Without requiring software or firmware changes?	Y ☐ N ☐

4.6 Standards

The elements of the infrastructure and the ways in which they interrelate are clearly defined, published, useful, open and stable over time.

4.6.1	Are the specifications for connecting to the system complete (i.e. they are not still in development)?	Y ☐	N ☐
4.6.2	Have the specifications for connecting to the system been published?	Y ☐	N ☐
4.6.3	Are the specifications for connecting to the system available online?	Y ☐	N ☐
4.6.4	Have the specifications for connecting to the system been available for more than two years?	Y ☐	N ☐
4.6.5	Are the specifications for connecting to the system used elsewhere in the world?	Y ☐	N ☐

4.6.6	Are the specifications for connecting to the system recognized by any of the following bodies?		
	a) An international standards body, e.g. the ISO, IEEE, or IEC?	Y ☐	N ☐
	b) A national standards body, e.g. ANSI, CSA, CEN?	Y ☐	N ☐
	c) An industry consortium, e.g. ASHRAE, OpenAMI, DNP User's Group	Y ☐	N ☐

4.6.7	Is there an independent (non-vendor) organization that is responsible for updating the specifications for the system?	Y ☐	N ☐
4.6.8	Do the system performance targets make reference to an open, published standard?	Y ☐	N ☐
4.6.9	Do the security measures applied to the system follow open, published standards?	Y ☐	N ☐

4.6.10	Has another regulatory body, system operator, or utility approved for use in its jurisdiction:	Y ☐	N ☐
	a) This AMI system?	Y ☐	N ☐

b) Another AMI system from the same vendor(s)?	Y ☐ N ☐
c) The technology underlying this AMI system?	Y ☐ N ☐

4.7 Openness

The infrastructure is available to all qualified entities on a nondiscriminatory basis.

4.7.1 Is the equipment for the system available from more than one vendor?	Y ☐ N ☐
4.7.2 Are the specifications for connecting to the system available to anyone?	Y ☐ N ☐
4.7.3 Are the specifications for connecting to the system available at low cost (i.e. no more than necessary to administer their distribution and promotion)?	Y ☐ N ☐
4.7.4 Can any vendor connect equipment to the system without providing profit to a competitor?	Y ☐ N ☐
4.7.5 Is the body responsible for updating the specifications a non-profit organization?	Y ☐ N ☐

4.7.6 Is there a published, standardized specification describing exactly how to do *each* of the following items?	
a) Connect a meter to the system?	Y ☐ N ☐
b) Connect customer premise equipment to the system, such as load control devices and automated building management systems?	Y ☐ N ☐
c) Connect distributed generation equipment to the system, monitor it and control it?	Y ☐ N ☐
d) Change a tariff?	Y ☐ N ☐
e) Incorporate a different communications network into the system?	Y ☐ N ☐
f) Read any meter in the system?	Y ☐ N ☐
g) Induce demand response in any consumer or group of consumers?	Y ☐ N ☐
h) Access individual and aggregate load profiles?	Y ☐ N ☐

4.7.7	Can the communications networks used by the system co-exist (not interfere) with the networks used by nearby systems belonging to other vendors or other utilities?	Y ☐ N ☐
4.7.8	Is there a single, standard specification for the data exchanged in the system such that it can be carried over a variety of different communications technologies?	Y ☐ N ☐

4.8 Security

The infrastructure is protected against unauthorized access, interference with normal operation; it consistently implements information privacy and other security policies.

4.8.1	Does the system prevent unauthorized users from doing any or all of the following?	
	a) Accessing personal information about consumers?	Y ☐ N ☐
	b) Reading energy usage or cost information for a given consumer?	Y ☐ N ☐
	c) Downloading incorrect tariff schedules, load control requests, software, firmware, or other data to equipment at a consumer site?	Y ☐ N ☐
	d) Controlling load at the customer site?	Y ☐ N ☐

4.8.2	Does the system prevent *any* user (authorized or not) from tampering with the energy usage data supplied from the consumer site?	Y ☐ N ☐
4.8.3	Does the system restrict access to different parts of the system based on the role of the user making the request?	Y ☐ N ☐
4.8.4	Does the system make appropriate use of standard network security equipment and practices such as firewalls and intrusion detection systems?	Y ☐ N ☐
4.8.5	Does the system permit centralized control of security credentials like passwords, keys, and certificates?	Y ☐ N ☐
4.8.6	Does the system have a published default security policy that utilities can use as the basis for developing their own policies?	Y ☐ N ☐

4.8.7	Does the system provide audit logs of all configuration changes, including:	
	a) Tariff changes?	Y ☐ N ☐
	b) Software or firmware changes?	Y ☐ N ☐
	c) Load control requests?	Y ☐ N ☐
	d) Addition or deletion of consumers?	Y ☐ N ☐
	e) Changes to personal information?	Y ☐ N ☐

4.8.8	Does the system perform these security functions while permitting authorized users to access any of the data discussed under "Shareability"?	Y ☐ N ☐
4.8.9	Does the system perform these security functions while adhering to open standards as discussed under "Standards" and "Openness"?	Y ☐ N ☐

5 How to Use the Checklist

Regulators, system operators, and utilities should use the checklist in section 4 to evaluate AMI systems and projects using the following procedure:

1. Determine what stage of evolution towards open systems that this particular project is in, and identify those checklist items for which an answer of "in the future" is permitted.
2. Determine the response of the vendor to the checklist. This may be done in one of three ways:
    a. Issue the checklist to vendors along with the bid package
    b. Issue selected questions from the checklist to vendors after examining their bid responses
    c. Issue the checklist to vendors as a separate document before or after the formal bid
3. Based on the vendors' responses, determine what the vendor believes to be the boundaries of the AMI system, as discussed in section 6.4.
4. Resolve any disputes regarding the system boundary and the responsibilities of the vendor in fulfilling the items on checklist.
5. Compare the responses of multiple vendors to the checklist.
6. Select vendors who:
    a. Provided the most "Yes" answers.
    b. Provided the most "In the future" answers where those were permitted.
    c. Define the boundaries of the AMI system in a manner consistent with this project.
    d. Seem to most agree with the idea of evolution to open systems
    e. Provide milestones for evolution consistent with this project

6 Critical Issues and Recommendations

The checklist in section 4 is intended to highlight, for any particular project, several issues that are critical to the development of AMI systems in today's market. These issues are discussed in this section, along with recommendations for addressing them in the requirements phase of a project. In general, these issues arise because of a conflict between two economic forces:

- **Long-term cost savings arising from an open system.** The more effectively the eight OpenAMI principles are applied, the more the size of the AMI market will increase, the more vendors will become involved, and the more costs of individual projects will drop.
- **Short-term costs of adding open system capabilities on a large scale.** Most of the eight OpenAMI principles have a significant impact on the cost of either the communications network or the remote equipment. Initially, the costs of developing these capabilities will present a barrier to entry for open systems.

6.1 Planning for Evolution

The classic solution for the conflict between short-term pain and long-term gain is to develop a system that can evolve. Doing so will reduce the immediate short-term costs but also encourage vendors to make longer term investment. This vision is discussed in detail in section 3.8.

Regulators should:

6.1.1 Clearly identify their commitment to open systems and which portions of AMI systems they expect to be standardized in the future.

6.1.2 Ensure vendors are committed to evolution to open systems and have a published, detailed plan for getting there.

6.1.3 Identify clear milestones for the evolution of particular AMI projects and realistic schedules for achieving these milestones.

6.1.4 Make it clear that open systems functionality is a requirement for *all* vendors in the market and that initial costs will therefore have the same impact on all competitors.

6.2 Encouraging and Re-Using Two-Way Networks

One of the chief arguments against a truly open AMI system has been that many of the features of an open system require an expensive two-way communications network. The example in section 3.7 shows that this need not necessarily be the case. A properly designed AMI system can be independent of whether it is implemented on a one-way or two-way network. However, if a two-way network really is required, there are ways to mitigate the cost.

Regulators should:

6.2.1 Require that vendors use standards (e.g. Internet Protocols) that make it possible to re-use existing two-way networks, such as cable, Digital Subscriber Line, cellular telephony, and two-way paging.

6.2.2 Encourage the use of emerging commercial standards such as wireless wide-area networks that will come down in cost as they are deployed for non-utility use.

6.2.3 Start by specifying and using separate one-way networks, but ensure vendors base them on a common design so they can be linked together when two-way networks become more common.

6.3 Ensuring Co-existence and Security

A key factor in developing an evolution plan toward open systems is that the system will not evolve if certain key OpenAMI principles are not applied *from the very beginning.* Two of these are co-existence (geographical overlap), and security. As discussed in section 3.8, it should be the goal of regulators to evolve AMI from largely proprietary systems with few standard interfaces, to open systems with many standardized interfaces.

To do this, regulators *must*:

6.3.1 Ensure that even proprietary systems protect the personal information and data of consumers from eavesdropping, tampering, and impersonation, especially from nearby networks that use similar technologies.

6.3.2 Ensure that proprietary systems permit their systems to co-exist with, and overlap geographically with, proprietary systems from other vendors in the market.

6.4 Identifying the System Boundary

As shown in Figure 1 on page 9, one of the first actions that the OpenAMI task force took was to clearly identify the boundary of what was considered to be "the AMI System". The reason for this is that the ALJ rulings are unclear where this boundary lies and therefore what particular functions a vendor of an AMI system will be responsible for.

There are functions that are vital to the success of AMI systems, and in particular, demand-response systems, that have not traditionally been the responsibility of AMI vendors. Some examples of such functions are those that deal with:

- Supplying energy usage and cost to consumers
- Notifying consumers of tariff changes
- Permitting more frequent billing
- Permitting access to data by metering service providers

An AMI vendor would typically say that such functions are the responsibility of some domain *other* than the AMI system, e.g. the billing department, the customer service department, perhaps even the regulator or the ISO. Some more specialized vendors might draw the boundary still smaller, to the metering systems only, or even to just the metering equipment itself.

The checklist in section 4 takes a wider view, one that seems to be implied in parts of the ALJ ruling, that while the AMI system may be contained within the boundary identified in Figure 1, the regulator must specify not only the AMI system but how it interacts with consumers and works in concert with other domains.

Therefore, regulators should:

6.4.1 Make it clear which of the requirements in this checklist that AMI vendors are responsible for directly, which they must cooperate with other organizations to ensure, and which they will not be responsible for, on a given project.

6.4.2 Clearly identify the boundaries of responsibility in any requirements document that may be produced similar to the ALJ rulings.

Appendix A – Requirements from CPUC Orders

Functionality Requirements for AMI Networks in Previous CPUC orders

Source: 2/19/04 ALJ ruling 02-06-001

1. Capable of supporting the following price responsive tariffs for:
    a. Residential and Small Commercial Customers (<200kW) on an opt out basis:
        i. Two or Three Period Time of Use (TOU) rates with ability to change TOU period length;
        ii. Critical Peak Pricing with fixed (day ahead) notification (CPP- F);
        iii. Critical Peak Pricing with variable or hourly notification (CPP-V) rates;
        iv. Inverted tier or flat rates.
    b. Large Customers (200 kW to 1 MW) on an opt out basis:
        i. CPP; [fixed or variable notification]
        ii. TOU;
        iii. Two part hourly Real Time Pricing (RTP)
    c. Very large customers (over 1 MW) on an opt out basis:
        i. Two part hourly real-time pricing (RTP);
        ii. Critical peak pricing (CPP); [fixed or variable notification]
        iii. Time-of-Use (TOU) Pricing

Supports the following functions:

2. Collection of energy usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how their own usage patterns relate to energy costs

3. Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.

4. Compatible with applications that provide customer education and energy management information, customized billing, complaint resolution

5. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

6. Capable of interfacing with load control communication technology

Appendix B – WG3 Report

WG3 Meter Functional Specification Subgroup

Functional Requirements for the AMI System

<u>Summary</u>

On February 25th, representatives from the investor owned utilities, system vendors and other interested parties participated in a conference call to establish the functional requirements that define the AMI (automated metering infrastructure) system capabilities to be economically evaluated in the business case. Table 1 lists all of the participants identified from the conference roll. Several other individuals that could not be identified also participated actively or as observers.

Defining Functional Requirements

The actual hardware and software that define both the cost and capability of an AMI system are driven by three distinct sets of definitions (Figure 1).

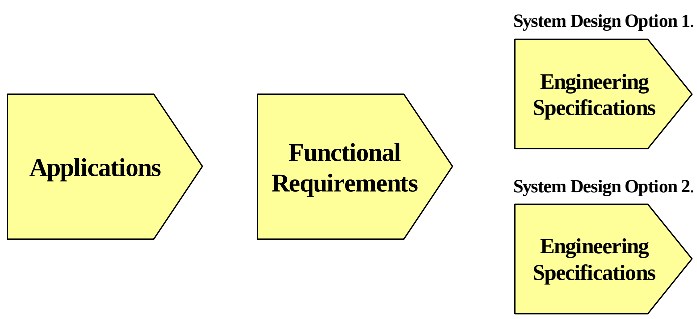


Figure 1. AMI System Design Stages

Applications define the highest level of AMI system capability. Applications provide an integrated view of how data collection, data processing, and communication work together to accomplish a specific objective. For example, pages 3-4 of the Joint Assigned Commissioner and Administrative Law Judge Ruling (ACR) list a variety of rate options, system (e.g. remote meter reading and outage management) and information applications. An RTP rate implies a certain level of interval data collection, data processing and communication capability that is quite different than a flat or inverted tier rate. The ACR, September 19th and November 24th rulings and Vision Statement provided the applications considered during our workgroup session.

Functional requirements define the common set of data collection (interval and other data), data processing and communication capabilities necessary to support the preferred list of applications, which in turn determine the cost of the AMI system. Functional requirements should provide sufficient information to allow translation into engineering and other detailed system specifications. While the preferred rate and system applications may differ in how they combine, process and communicate data all may share common hardware and system components. The purpose of the functional requirements is to identify the common system capabilities necessary to support the preferred rate and system applications.

The cost to provide these common AMI system capabilities is separate and distinct from the cost to implement any specific rate option or system application (ACR footnote #3). The applications included in this specification are the minimum necessary to implement the functions described in the February 25th ACR. Additional specific applications could be added to the extent they are found to be cost-effective to development of the business case or essential components of customer service.

Engineering specifications translate the functional requirements into detailed hardware and software components. The same set of functional requirements may translate into engineering specifications that produce entirely different system designs in each utility service territory. For example, engineering specifications for one system design may specify that all interval data be stored in the meter, while another may specify that interval data be stored in a 'concentrator' that serves multiple meters. While each system design option has different cost, reliability, and system operating implications, all system designs should provide the capability to fully support the functional requirements and thereby also support the minimum application set.

<u>AMI System Objective</u>

According to the ACR, AMI systems should provide metering and communication capability to support a wide variety of economically justified rate and associated customer service options. The ideal AMI system should maximize the amount of demand response that can be achieved cost effectively. The specific mix of rates, programs and customer service functions that will eventually satisfy this cost effective ideal is not known a priori. Consequently, the AMI system should be designed with the flexibility to anticipate and support a wide variety of potential rate structures and customer service options that the Commission may approve over the useful life of the AMI system.

Workgroup Results

1. <u>Implementation Scope.</u>

The ACR and previous Commission rulings clarify that full scale implementation will provide all customers in all rate classes with AMI capabilities and the option to choose between dynamic and static rate structures.

The ACR, however, does differentiate potential rate offerings for different groups of customers, specifically: (a) very large customers (> 1 MW), (b) large customers (200kW to 1 MW), and (c) residential and small commercial customers (<200kW). This differentiation has implications for both the level of interval data (e.g. 15, 30 or 60 minute data) collected from each customer and the types of applications eventually supported.

The workgroup suggests the following additional clarifications:

- Implementation should anticipate that while all classes of customers (residential, agricultural, commercial and industrial) will be addressed, it is not economically, technically or practical to guarantee implementation on 100 percent of the customer sites. There will be a small percentage of customers for whom installation of AMI is not practical or economic given geographic remoteness, population density or other technical constraints. The utility business case should identify these exceptions and also identify what alternatives will be provided to assure support for dynamic pricing and other services supported by AMI.
- The scope of implementation needs to be clarified to identify whether the definition of "all classes of customers" includes (1) direct access customers and (2) customers that own their meters.
- Additional metering system differentiation may be necessary to address recording interval and other technical issues for medium size commercial / industrial customers with demands between 20kW and 200kW. See recommendations under 1b for a more complete explanation.
- Specific types of metered accounts such as billboards, street lighting and other similar applications may be excluded or targeted for more limited metering capability.
- It is also recognized that no single meter, meter system design or communication technology may be suitable to serve all customer segments within a single utility service area. In some cases multiple systems, employing a variety of metering and communication technologies may be necessary.
- Combined electric and gas utilities may include basic gas metering in their AMI business case. Estimated costs for gas and electric meters will provide comparable functionality.

In each case the utilities will clearly identify the criteria for each decision, any exclusions and number of customers affected.

2. <u>Technology Preferences.</u>

No single metering or communication technology is preferred one over the other. Technology choice should be driven by functional, engineering and economic performance. Technology choice and engineering features should be left to individual utilities. Meter system functional specifications assume compliance with all net metering, safety, data accuracy and other legal requirements not directly addressed by the ACR.

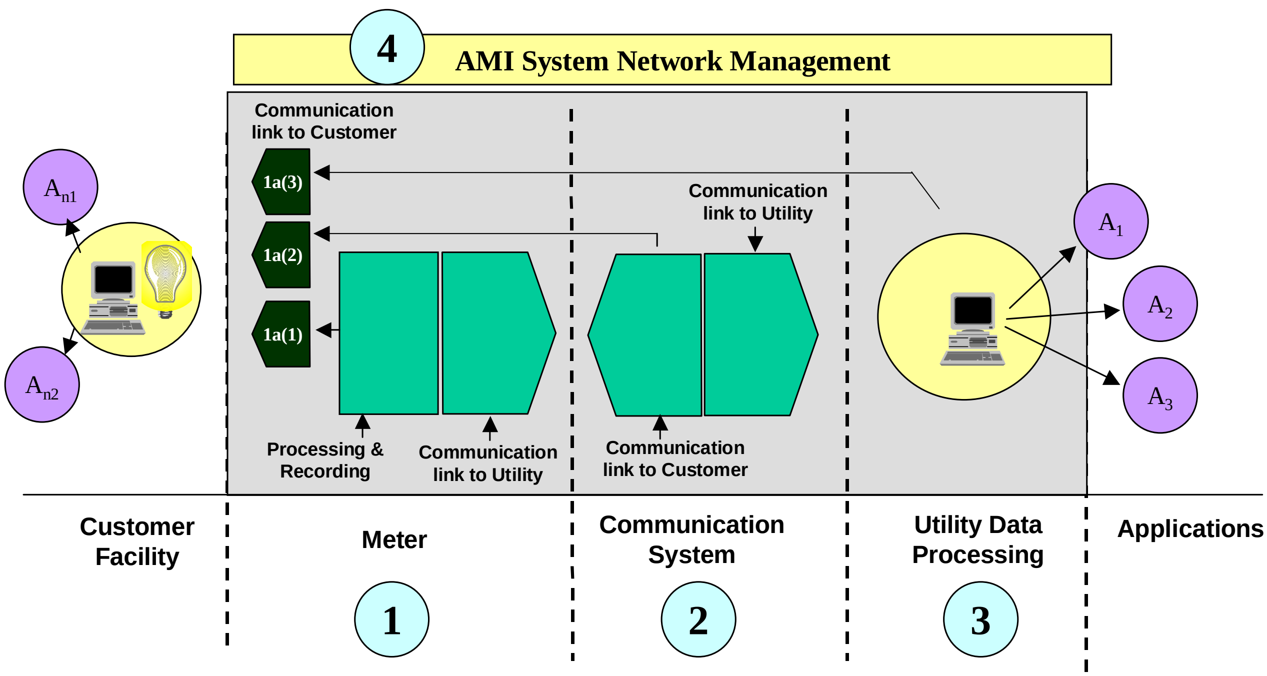
3. <u>System Design.</u>

AMI systems can require the integration of multiple metering, communication and data processing technologies. While minimum functional requirements narrow the technology choices for each system component, the actual technologies selected and how they are combined into a system still requires substantial engineering, economic and operational judgment. Customer mix, geography, transmission/distribution and other electric system design features, as well as customer service philosophy can substantially affect which metering and communication technologies a utility selects and how they combine them into a fully functional AMI system. As a consequence, there is no single best AMI system design. It is likely that each of the participating utilities will choose different AMI system components and designs as the basis for the business case.

4. System Functional Requirements and Additional Subgroup Recommendations.

AMI systems combine three integrated components that define distinct data collection and data communication functional requirements. Figure 2 graphically depicts the three AMI system components and how they relate to both customer and system applications. Table 1 provides an overview of the system functional requirements.

Figure 2. AMI System Components



System Component	Description / Discussion	Issues Requiring Clarification
1. Meters	Meter systems generally include a variety of sensing, recording, processing, and communication capability. At a minimum, the meter system must provide capability to sense and record various electric operations and then communicate information back to the utility. Basic functional capabilities should include capability to: x collect and store interval data (see issues) x provide processing at the meter or within the system, where necessary, to support essential customer service and system operating applications. x provide optional capability to support customers with direct or other real-time access to meter data x provide capability to remotely access (download or otherwise communicate) meter data to support customer billing, system operation and customer service and educational applications	The resolution of interval data collected is usually determined by the specific rate, information or system application to be supported. While the ACR specifies different potential combinations of rates targeted to three distinct classifications of customers, Appendix A specifies that interval data will be collected at a minimum of 15-minute intervals. The resolution of interval data collected will affect AMI system specifications and cost. The utilities recommend a clarification of interval data recording to differentiate between the customer classifications. There is consensus on the largest C/I and smallest Residential customers, however there is a lack of consensus regarding the breakpoint C/I customer in the middle. See 1b for Subgroup recommendation. <u>Recommendation by the Function Subgroup</u> Meter system functional specifications assume compliance with all net metering, safety, data accuracy and other legal requirements not directly addressed by the ACR.
1a. Communication Link to the Customer	Meter systems may also include capability to (a) allow customers to use supplementary equipment to connect to and access real-time information directly from the meter (hard wired KYZ port) (b) communicate information wirelessly in real-time from the meter directly into the customer facility, or At a minimum, the AMI system should provide capability to communicate information to the customer through other hardwire, wireless, internet, paper or other means in less than real-time. Direct, real-time access to meter data may be useful in supporting energy management, energy monitoring or other customer display applications. This is particularly true for the largest C/I customers. Any communication from the meter directly into the customer facility	There is consensus that all customers may need or can use access to their energy usage information. However, there is no consensus regarding either the customer need for or technology necessary to support real-time access to meter data. There is consensus on two points: (1) a real-time link would raise the cost of the meter and (2) the largest C/I customers have a more established need for this type of information than small C/I or residential. <u>Recommendation by the Function Subgroup</u> x Require hard-wire or wireless options for accessing real-time data from the meter for the largest C/I customers (1) For >200 kW under AB1X29, real time is defined as a hard wire option through a KYZ port at the meter or through a utility provided Internet link that provides a minimum 24

System Component	Description / Discussion	Issues Requiring Clarification
	should be governed by non-proprietary, open-protocol communication standards. Access to less than real-time meter data through other means may be particularly useful to all types of customers to support educational, facility management and other functions.	hour turnaround. (2) For <200 kW, utilities should identify options that are at a minimum compatible with the same interval recording detail listed in the recommendation under 1b. bullet #2. x Communication from the meter directly into the customer facility should be governed by non-proprietary, open-protocol communication standards. x Allow utilities to specify or make available real-time access to other customers either with economic justification or as a customer charge option. x Require utilities provide customers with several different options to gain access to less than real-time meter data.
1b. Processing and Recording	What is processed and stored at the meter, in local nodes or concentrators that aggregate multiple meters, or in the utility data processing system is determined by the overall system design and basic tradeoffs between the cost of communication and cost and value of data collection and storage. Collecting and processing interval data centrally for all meters on a daily basis, maximizes potential information value by providing immediate access to detailed system operating data and provides great flexibility to quickly change and implement new rate designs. However, there is a tradeoff that must be made between how often and at what level of detail data is collected. Specifically, collecting interval data from all meters daily versus less frequent collection of only the register data necessary to support the customer rate involves a tradeoff in communication, data processing and data storage costs versus application support. The collection, communication and storage of interval data or the same interval recording detail may not be identical or even required for all customers. Rate designs (e.g. RTP, interruptible and demand rates) and system applications (e.g. load survey, outage reporting, etc.) may require different levels of interval data collection and then only from subsets of customers. Meter recording and data transmission capabilities will be driven by three	<u>Recommendation by the Function Subgroup</u>: x Adopt the 15-minute interval data recording level already in place and specified in for the largest C/I customers. x Require the utility AMI meter and system design explicitly address what level of interval data will be established as the default for all other customers below 200 kW. Design requirements should address each of the following: (1) Existing and anticipated rate design/tariff requirements for interval data (2) Existing and potential markets for demand response both at the retail and wholesale level as well as potential aggregation to support ancillary services and other reliability programs, and (3) Utility system operational needs for support of outage management, load survey, customer education and bill inquiry resolution. x Furthermore, utility AMI system designs should be required to provide and/or explicitly address capability to remotely redefine the time boundary or other register

System Component	Description / Discussion	Issues Requiring Clarification
	factors – (1) Billing determinants necessary to support the customer rate. a. Centrally processed 15 minute interval data can be collected from each meter and centrally processed to support almost all possible rate designs, however b. Locally processed aggregated meter register data can be used to support most tiered, time-of-use (TOU) and Critical Peak (CPP) rates. To retain flexibility, AMI system designs should provide and/or explicitly address capability to remotely redefine the time boundary or other register collection parameters. (2) Information necessary to support customer billing inquires and system operating and service functions. While customer billing may not require the collection of interval data, selective access to interval data may be necessary to support customer billing inquiries, load survey, system planning, outage management and customer educational applications. (3) Customer information and educational applications - Interval level data in the form of a daily load curve can be instrumental in educating customers regarding how they use energy and what they can do to better manage their energy bill. If interval data is not collected and stored centrally, provision must be made to store data locally sufficient to support anticipated applications and to remotely access this data on demand. See (2).	collection parameters.
1c. Communication Link to the Utility	Communication capability from the meter to the local node/utility can be supported by a variety of communication methodologies and either integrated or linked system designs. How often data is uploaded from the meter is a dependent upon the system design and the tradeoffs inherent in various system operating and customer service applications. Alarm functions that trigger automatic communication from the meter to the utility may allow less frequent polling and data collection from the remaining meters population.	No significant issues.

System Component	Description / Discussion	Issues Requiring Clarification
2. Communication System	The communication technology choice and system design will be driven by (1) decisions regarding processing and recording, (2) assumptions regarding customer participation and the mix of rates and programs and (3) timing needs of selected system operating and customer service applications. Because of the uncertainties regarding customer participation and the eventual mix of rate designs and program, the actual volume of data transport that needs to be supported is also uncertain.	<u>Recommendation by the Function Subgroup</u>: x Communication systems technologies should be capable of being economically scaled up or down in response to anticipated customer participation levels. x Utilities will be obligated to provide AMI to all customers in all classes, to support as yet undecided rate options. As a result, some minimum level of communication infrastructure must be available 100 percent of the time. Utility business cases should clarify both the design and economic justification for what is proposed.
3. Utility Data Processing	Interval and register data must be validated and edited, at a minimum, in accordance with CPUC billing quality standards. Data must also be integrated into a master customer database to support billing and other utility system functions. As with Communication system requirement, there are uncertainties regarding customer participation, the eventual mix of rate designs and program, and consequent data processing requirements. As a result, data processing systems should be capable of being economically scaled up or down in response to anticipated customer participation levels.	No significant issues.
4. AMI System Network Management	Network management capability must be provided to manage meter data collection schedules, meter and communication system alarms and all other system maintenance and operating functions.	<u>Recommendation by the Function Subgroup</u>: To guarantee open information exchange between legacy, future utility systems and potential third-party customer applications, AMI designs should anticipate and separate information exchange requirements into hierarchical categories to accommodate interoperability.

Table 1. WG3 Meter Functional Specification Subgroup

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Appendix C - Administrative Law Judge Ruling

MP1/MLC/hl2 2/19/2004

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on policies and practices for advanced metering, demand response, and dynamic pricing.	*Rulemaking 02-06-001* (Filed June 6, 2002)

JOINT ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING PROVIDING GUIDANCE FOR THE ADVANCED METERING INFRASTRUCTURE BUSINESS CASE ANALYSIS

1 Summary

This ruling provides policy direction regarding the minimum level of system functionality that should be supported by an advanced metering infrastructure (AMI) for purposes of analyzing full-scale AMI deployment. The ruling also addresses which customer classes should be included in the AMI analysis, clarifies the costs to be included in the base case AMI analysis, directs the Working Group 3 (WG3) moderator to schedule a workshop to review sources of avoided costs for valuing peak demand reductions, seeks input on the need for a workshop on methodologies for estimating demand response, and clarifies the meaning of “out of scope” impacts.

2 Background

The purpose of this proceeding is to increase the level of demand response, in particular price responsive demand, “as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment.”[1] California’s energy agencies have already provided some guidance on the types of rates and technologies to be supported by the AMI system in the vision statement appended to Decision 03-06-032 as Attachment A. The rate options and technology functionalities outlined in the vision statement can be utilized as the framework for the AMI system functionality and business case analysis.[2]

3 Guidance on AMI System Functionality

Agency staff from the California Energy Commission (CEC) and this Commission report that participants at the January 28, 2004 AMI workshop requested additional direction on the types of rate structures the AMI system should support and more specificity on the functional requirements of the full scale AMI system for purposes of developing the AMI business cases. Agency staff report that the AMI system functionality requirements are driven by the type of rate structures and programs the system is expected to support.

The purpose of an AMI system is to provide the metering and communications capability to economically support a wide variety of rate and associated customer service options. The ideal AMI system will maximize the amount of demand response that can be achieved cost effectively. We do not know *a priori* the particular mix of rates, programs, and customer service functions that will meet this

[1] Ruling 02-06-001, p. 1.

[2] Key bullets related to AMI business case are reprinted as Appendix A of this ruling.

cost effective ideal. Thus it makes sense to analyze an AMI system that supports a wide variety of potential rate structures and customer service options that the Commission may approve over the useful life of the AMI system.

As indicated in the original rulemaking, we prefer to take a broad view of the investigation of AMI. The Commission can always authorize a narrower scope AMI system implementation if warranted, but it is more difficult to expand functionality if it has not been considered in the business case analysis. Therefore, the AMI system analyzed should support the following six functions:

a. Implementation of the following price responsive tariffs[3] for:
   (1) Residential and Small Commercial Customers (200kW) on an opt out basis:
      (a) Two or Three Period Time-of-Use (TOU) rates with ability to change TOU period length;
      (b) Critical Peak Pricing with fixed (day ahead) notification (CPP- F);
      (c) Critical Peak Pricing with variable or hourly notification (CPP-V) rates;
      (d) Flat/inverted tier rates.
   (2) Large Customers (200 kW to 1 MW) on an opt out basis:
      (a) Critical Peak Pricing with fixed or variable notification;
      (b) Time-of-Use;
      (c) Two part hourly Real-Time Pricing.
   (3) Very large customers (over 1 MW) on an opt out basis:
      (a) Two part hourly Real-Time Pricing;
      (b) Critical Peak Pricing with fixed or variable notification;
      (c) Time-of-Use Pricing.
b. Collection of usage data at a level of detail (interval data) that supports customer understanding of hourly usage patterns and how those usage patterns relate to energy costs.
c. Customer access to personal energy usage data with sufficient flexibility to ensure that changes in customer preference of access frequency do not result in additional AMI system hardware costs.
d. Compatible with applications that utilize collected data to provide customer education and energy management information, customized billing, and support improved complaint resolution.

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[3] The costs of developing an AMI system capable of supporting a variety of rate designs and customer service applications must be separated from the actual costs associated with implementing a specific new tariff. If a party chooses to estimate the benefits of a particular dynamic rate in its AMI analysis, the benefits and the costs of implementing that rate (such as customer education or billing changes) should be separated from core costs of developing and installing AMI hardware, software, and communications systems.

e. Compatible with utility system applications that promote and enhance system operating efficiency and improve service reliability, such as remote meter reading, outage management, reduction of theft and diversion, improved forecasting, workforce management, etc.

f. Capable of interfacing with load control communication technology.

We recognize that there may be additional levels of “system” functionality or technical requirements that need to be specified by the utility and other parties to ensure accurate cost comparisons between different AMI systems. These may relate to the frequency of meter polling, scalability of IT infrastructure, the amount of data storage in meters versus other collection points in the network, and communications systems needed to support these functions. These specifications are best handled by the experts and we urge the “functionality” subcommittee set up by WG3 to develop a matrix that includes any additional specifications necessary to implement the policy direction above.

4 Customer Classes to be Included in the AMI Analysis

At the workshop, additional questions surfaced about which customer classes are to be included in the AMI system cost benefit analysis. Some parties indicated they plan to propose deployment of an AMI system serving only the mass market (residential and small commercial customers).

We clarify that the Commission anticipates that full scale implementation of AMI will provide **all** customers in **all** rate classes with the option to choose between dynamic and static rate structures. We are not interested in an analysis of the costs and benefits of AMI that is limited to residential or small commercial customers because system benefits inure to all customer classes that cannot be separated from the costs of AMI deployment. While we can compartmentalize the costs of AMI and load control systems to specific customer classes, it is not possible to isolate the benefits from demand response to one or more customer class since the system-wide benefits of demand response will flow to all classes. Thus the costs and benefits to of deploying an AMI system all customer classes must be quantified.

5 Costs to be Included in Base Case AMI Scenario

The September 19, 2003 ruling indicated that “(t)he Base Case must identify the actual costs of maintaining the existing metering and related support systems” and “identify the any significant investments in new metering systems made during the last five years.” (See September 19, 2003 Assigned Commissioner and Administrative Law Judge’s Ruling, Attachment A, p. 7.) Despite this guidance, at the January 28, 2004 workshop, some parties proposed to develop incremental cost estimates for the full and partial deployment of AMI scenarios without describing their estimates of maintaining their metering and billing systems in the base case. This information is important because without knowing what additional costs utilities have recently incurred and are expect to incur in the next several years for existing metering, billing, and other back office systems, it is impossible to develop an accurate estimate of the incremental costs of partial or full scale AMI deployment. Thus we expect the scenario analysis to include a full accounting of all of the costs of installing and maintaining the metering and related support systems for the base case, partial deployment and full scale AMI deployment scenarios.[4]

6 Methodology to use in the Valuation of Demand Response Benefits

At the workshop some participants suggested there was a need to hold a workshop to develop a common methodology to quantify avoided costs for use in valuing peak demand reductions. We agree that a workshop on this topic would be useful and direct the WG3 moderator to schedule a workshop to review potential sources of avoided costs for inputs in the AMI business case analysis.[5]

Participants also suggested that a workshop be held to develop a common methodology to estimate the level of demand response that could be available by customer class as a result of the AMI deployment scenarios. We are not sure if having a workshop on the demand response impact methodology is appropriate now given that WG3 is focused on reviewing load impacts from the Statewide Pricing Pilot and WG2 members are focused on developing estimates of demand response impacts for the March 31, 2004 filing. We solicit input from parties on the need to hold a workshop on methodologies for estimating demand response in the near term. Parties should provide their input to the WG3 moderator via email (Mmesseng@energy.state.ca.us) with a copy to ALJ Cooke (mlc@cpuc.ca.gov) by February 25, 2004.

7 "Out of Scope" Impacts

Some parties appear to have misunderstood the "out of scope" categorization of impacts referenced in the November 24, 2003 Assigned Commissioner's Ruling. "Out of scope" is intended to mean the impact will not be relevant to the decision of this proceeding. "Out of scope" does not mean "difficult to quantify" or "unrelated to utility cash flow" as some parties appear to suggest. We expect that impacts will be assessed at some level, whether using rigorous quantitative methods or more qualitatively. To the extent that assessments have to rely upon limited data (creating greater uncertainty

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[4] For example, the analysis should identify whether separate metering, billing, customer information, and communication systems will serve each customer class or a common system will serve all customers, whether new systems will be developed or existing systems can be modified to achieve the same functionality and the potential cost of these options.

[5] We note that on February 6, 2004, the Assigned Commissioner in R.01-08-028 (the Energy Efficiency Rulemaking) issued a ruling setting a workshop in June 2004 to address issues surrounding avoided costs. (See http://www.cpuc.ca.gov/WORD_PDF/RULINGS/33895.doc.) We do not intend to duplicate the purpose of that workshop here but hope that the workshop in this docket will allow us to provide guidance on what avoided cost inputs should be utilized in the AMI business case analysis on a more expedited schedule than would be possible were we to await the results of the workshop in R.01-08-028.

about a particular cost or benefit), it is appropriate to document these instances in the actual AMI analysis.

Therefore, **IT IS RULED** that:

The advanced metering infrastructure (AMI) system analyzed should (at a minimum) support the functions set forth in Section 3 herein.

The costs and benefits of deploying an AMI system to all customer classes must be analyzed in the business case.

Expected costs for maintaining existing metering, billing, and other back office systems must be quantified as part of the base case scenario.

The Working Group 3 (WG3) moderator should schedule a workshop to review potential sources of avoided costs for inputs into the business case analysis.

Parties should provide input to the WG3 facilitator by email (Mmesseng@energy.state.ca.us) with a copy to ALJ Cooke (mlc@cpuc.ca.gov) by February 25, 2004 about the need to hold a workshop in the near term on methodologies for estimating demand response.

Difficult to quantify impacts should still be assessed in the AMI analysis, even if a more qualitative assessment is required to do so.

Dated February 19, 2004, at San Francisco, California.

/s/ MICHAEL R. PEEVEY

Michael R. Peevey
Assigned Commissioner

/s/ MICHELLE COOKE by LTC

Michelle Cooke
Administrative Law Judge

Appendix A

Previous Guidance on the Scope of the AMI Analysis

From Decision 03-06-032, Attachment A, p. 3.

- Technologies to enable demand response may also provide other customer service benefits including outage detection and management, power quality management, and other information capabilities

  …

- Customers should have the ability to choose voluntarily among various tariff options, including:
  - Very large customers (over 1 MW): Hourly real-time pricing (RTP), critical peak pricing (CPP), or Time-of-Use (TOU) Pricing
  - Large customers (200 kW to 1 MW): CPP, TOU or RTP
  - Residential and small commercial customers (under 200 kW): CPP, TOU or flat rate (the latter with an appropriate hedge for risk protection)"

  …

- All customers should be provided an advanced metering system capable of supporting a TOU tariff or better, if cost-effective, and with minimal hardware upgrades necessary to choose among various dynamic tariffs.
- All customers who choose to should be able to conveniently access their usage information using communications media (e.g., over the internet, via on-site devices, or other means chosen by the customer and respectful of potential privacy concerns)
- The broadest possible range of metering and communications technologies that can enable demand response should be encouraged (i.e., optionality), but all technologies should be compatible with utility billing and other back-office systems

Additional guidance on the definition of full scale AMI implementation was presented in the draft analysis framework attached to the September 19, 2003 ruling. Full implementation was described as follows:

> Assumes full system implementation (gas and electric) over a five-year period with support for TOU, Critical Peak Pricing and two-part RTP for the largest C/I customers. Implementation should specify an advanced metering infrastructure (AMI) with interval metering (minimum 15 minute intervals) and remote communication capability. Useful modifications to outage detection and other operating systems that are associated with the use of the AMI system should also be specified.

CERTIFICATE OF SERVICE

I certify that I have by mail, and by electronic mail to the parties to which an electronic mail address has been provided, this day served a true copy of the original attached Joint Assigned Commissioner and Administrative Law Judge's Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis on all parties of record in this proceeding or their attorneys of record.

Dated February 19, 2004, at San Francisco, California.

/s/ KRIS KELLER

Kris Keller

N O T I C E

Parties should notify the Process Office, Public Utilities Commission, 505 Van Ness Avenue, Room 2000, San Francisco, CA 94102, of any change of address to insure that they continue to receive documents. You must indicate the proceeding number on the service list on which your name appears.

* *

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