Deciding on “Smart” Meters: The Technology Implications of Section 1252 of the Energy Policy Act Of 2005

Prepared for:

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September 2006

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Published by:
Edison Electric Institute
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Web site: www.eei.org

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ACKNOWLEDGEMENTS

This Guide was prepared by Plexus Research, Inc.

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with sponsorship from

Edison Electric Institute

The authors are indebted to the several reviewers whose comments helped refine this publication. We are especially indebted to the following colleagues for their suggestions, patience and unflagging enthusiasm for the project:

Eric Ackerman –	Edison Electric Institute
Mike Oldak –	Edison Electric Institute
Roger Levy –	Levy Associates
Ed Malemezian –	Ed Malemezian Consulting, Inc.

FOREWORD

Why was this Guide developed?

This Guide to the Technology Implications of Section 1252 of the Energy Policy Act of 2005 [PURPA Section 111 (d))] was developed to assist utilities, their managements and members of the regulatory community to convert policy into action. The EPAct, although lengthy, is rather concise in how it deals with peak-sensitive and time-sensitive pricing, demand reduction techniques, and "smart metering."

The Act, per se, does not require that utilities do anything. It requires that the regulators of regulated utilities, and the Boards of Directors of unregulated utilities, shall "consider and determine" what, if anything, the utilities in their jurisdiction must do to comply with the objectives of the Act. It sets timelines for when the consideration and determination shall occur, and when any requirements, if established as drafted, will become operative.

On one level, the Act's treatment of alternative rates, demand response and "smart metering" may seem simple and straightforward. But the Act creates some potentially burdensome deliberations and financially intimidating requirements for many utilities. The devil is in the details. Many utilities already have time-of-use (TOU) rates, have offered them since PURPA 1978 or even before that time, and still offer these rates. Many utilities have already made large investments in advanced metering systems, some of which are "smart" and others of which are not. Many utilities have offered TOU rates and have found that a large majority of customers are simply not interested unless they are "free riders" who will pay less without altering their consumption patterns. And other utilities may enthusiastically embrace new metering and price sensitive rates as important relief from the persistent growth in peak demand.

For all their similarities, it remains true that no two utilities are alike. This is never more certain than in consideration of PURPA. Fortunately, PURPA allows individual consideration before a determination is made. That consideration will address the significant differences among utilities in their needs, past practices, installed metering, rate design factors, customer preferences and dozens of other factors that come into play. This is a complex matter having major long term impacts on the utility and its customers. The authors hope this Guide will illuminate and simplify the whole process. It presents the background, the options, and the structure for an orderly decision process, so the determinations that are finally made will be made for all the right reasons.

EXECUTIVE SUMMARY

This monograph provides practical guidance on how to evaluate the cost-effectiveness of advanced metering infrastructures. It is written for EEI members and policy makers, and reflects an assumption that careful planning and implementation is the key to regulatory support for cost recovery.

Chapter I, Summary of Key Provisions of Section 1252, sets the context for the discussion by describing the "smart metering" standard of the Energy Policy Act of 2005. States are required to consider whether to implement time-based metering and communications, but have discretion to decide not to implement the standard, or to implement a modified standard.

Chapter II, Background & Selected Drivers, expands the context by providing a historical perspective on the energy issues that lead to the original Public Utility Regulatory Policies Act of 1978. PURPA addressed issues raised by the oil embargo of 1973 (e.g., the need to conserve electricity, to increase electric utility efficiency, to ensure equitable rates). Clearly, these issues remain relevant today.

Chapter III, Advanced Metering Justification, describes the development of a business case to support decisions about whether, and how, to deploy advanced metering infrastructure (AMI). Identifying the full range of operating benefits that modern AMI systems provide is a demanding and time-consuming task, because these systems typically produce benefits that reach into almost every department of the utility. It is vital that the business case be transparent (i.e., allow a variety of audiences, both within, and outside, the utility to understand the assumptions, relationships, benefits, and costs) because AMI represents a large investment and must be defensible in every way. The case also must facilitate revision, because AMI will involve multi-year budgets, and the business case will have to be revised periodically with then-current figures to re-calculate investment performance for the remaining life of the project.

For energy customers and society, benefits typically involve improved service quality, and benefits related demand response, which AMI enables. Bills are more accurate, and more timely; outages are detected more quickly, and restoration activities are faster and more efficient; energy losses due to theft and other causes are reduced, which reduces costs that must be borne by other customers; and system engineering improves with better load data. Demand response gives customers more control over their energy costs, and allows them to realize energy savings if they modify their consumption behavior. Demand response also can avoid costly outages when the system is stressed. Because such benefits are difficult to quantify, they frequently are not accounted for in business cases.

For utilities, savings related to the reduction or elimination of manual meter reading usually constitute the single greatest benefit, accounting for fully one third to two thirds of the total AMI benefit. Other quantifiable benefits vary significantly by utility, but can include the following: accelerated cash flow, revenues realized from new customer services, reduced capital needed as the result of less manual meter reading and optimal transformer sizing, savings realized through fewer billing inquiries and faster resolution of inquiries, savings in meter testing, savings through on-line bill paying, savings in the cost of load research, savings related to improved capacitor control and improved outage restoration, and reductions in non-billable consumption. A typical AMI business case will show that six or eight benefit sources (i.e., six or eight of the items listed in Figure 1, page 17) provide up to 75% of the total AMI benefit from traditional utility operations. The remaining 25% will come from 10 to 25 other sources in varying degrees.

The process by which AMI benefits are estimated is also important. Experience of the authors suggests that it is important to (1) assemble a team of representatives from all affected operating activities in the utility (e.g., metering, meter reading, customer service, distribution engineering, distribution operations, telecommunications, information technology, system planning, rates, regulatory relations), and (2) have executive charter and sponsorship.

AMI costs are more easily determined, and typically include the following elements: AMI system hardware & software, new meters and meter-related utility equipment and labor, installation management and labor, project management, and IT support and integration. Costs for automated remote meter reading are approximately $100 to $175 per meter. Adding demand response components (e.g., customer signaling, load control, other demand response equipment) adds another $100 to $350 per site.

Costs and benefits should be estimated for each AMI configuration being considered. Key summary metrics include the following: gross acquisition cost, net acquisition cost, annual O&M, annual net benefit, simple payback period, internal rate of return, and net present value of the AMI investment.

Chapter IV, The Enabling Technologies: A Brief Tutorial, reviews component technologies and products that can be used in advanced metering infrastructures. Interval meters (i.e., meters with internal clocks and ample memory to store time-tagged consumption data at 60, 30, 15, and 5 minute intervals) enable utilities to measure and bill customers' time-differentiated usage. The resulting data can be collected in any number of ways, depending on what is most economic in a given situation. For example, the data can be collected:

- Manually using a handheld terminal with an infrared optical probe.
- Via a “drive-by” approach in which, once a month, a vehicle passes within a few hundred feet of the meter and receives data via short-distance radio.
- Over a public communications infrastructure (e.g., telephone, cellular, or two-way paging).
- Over a fixed private network owned by the utility (e.g., radio frequency - RF - or power line carrier - PLC - technology).

Drive-by automatic meter reading (AMR) systems generally are not practical for residential time of use pricing and demand response applications. Because radio AMI systems tend to be more economic in urban environments, and power line systems often are more attractive in rural areas, utilities are considering hybrid systems that make use of both technologies, and technology vendors are forming alliances to offer mixed technology systems.

Communication to the customer's site (i.e., of time-differentiated prices) can be accomplished using the same path the AMI system uses to communicate with meters, or it can be done with private VHF or UHF radio, or a paging system, of VHF radio sub carriers, or digital cellular phone. Communication of load control signals also can be accomplished using meter communication pathways. Controllable thermostats offer another option for communicating price signals to end-use loads.

Meter data management systems (MDMS) are suites of software programs that receive and store meter data, and support a host of revenue cycle and other functions (e.g., billing, outage management, and distribution engineering). At least half a dozen well-established firms now offer MDMS suites.

Chapter V, Economic & Technical Implications of Technology Choice, examines the relationship between the level of expected customer participation and the optimal AMI configurations. If few customers are expected to participate in time-differentiated rates / demand response programs, drive-by AMR with “drop-in” technology for TOU reading will tend to be most cost-effective. If a majority of customers are expected to participate, saturation deployment of a fixed network AMI likely will be indicated. The versatility of fixed network systems reduces the risk of obsolescence.

The rate treatment accorded to the un-depreciated value of legacy meters can be a significant factor in AMI decisions. Also, the potential for significantly different depreciable lives of meters versus the communication modules that may be integrated in advanced meters can be problematic.

Chapter VI, Best Practices in Purchasing, Installation & Integration, provides advice on how to manage the AMI process. It is important to get the sequence right. First comes the vision of how the number of customers on different rate structures will change over time, by customer class. Then comes the development of one or more business cases that will identify attributes that produce the greatest benefit. Then comes the specification of functional requirements for metering and communication to support the vision. Then comes the development of a request for proposals (RFP), which centers on the high-value attributes of the envisioned system. Then comes the evaluation of proposals, and the normalization of costs to account for the variances in proposals that make it hard to compare them directly. Finally comes the negotiation of contracts to procure AMI and associated services.

It is important to recognize that the AMI process is complex and has nuances not found in other utility procurements, so it probably is a good idea to get help from a consulting firm that specializes in AMI. The cost of overstating requirements can be high. IT integration, described in relation to the MDMS (above), may be best accomplished through an outside firm that specializes in this. Procurement contracts must assure performance at the product level, and also at the system level. They also must anticipate warranty issues extending several years after deployment, including the possibility that the hardware supplier goes out of business. Turnkey contracts may be attractive, but will entail higher cost because the supplier bears additional risk. A variety of outsourcing models is possible, along a continuum of structures from the utility installing, owning, operating, and maintaining the system; to a vendor doing all this. The logistics of installing new meters can be daunting. Union bargaining unit issues often are prominent in installation planning.

Chapter VII, Lessons Learned from Prevailing Practice, reiterates six key insights, as follows:

1. Fixed network systems always discover new applications / sources of value beyond those originally expected.
2. It's a good idea to assign a top management sponsor to shepherd the AMI process.
3. You need to organize a task force of senior representatives from the many departments affected by AMI to earn buy-in within the organization.
4. AMI should be justified by operational cost savings, identified department by department, it usually takes 2-5 months to do this adequately.

5. Rate recovery of legacy metering is a key driver of AMI strategy, address this issue early.
6. After deployment, benchmarking actual savings against estimates in the business case is an effective way to measure and manage progress.

Chapter VIII, Decision Support Tools, provides the template for an AMI management plan. The three phases are Planning, Procurement, and Deployment. Within each phase key players and tasks are identified. AMI will affect the utility's future direction in many adjunct areas (e.g., load control/management/demand response, outage management, net metering, field force automation, remote service switching, distribution system planning, distribution automation, resource planning, prepayment service, customer-site automation). Informed utilities think very carefully about their long-range needs in these areas before launching an AMI procurement, and often will include requirements for all these applications in the AMI procurement process.

Chapter IX, Conclusions & Recommendations, recounts that the EPAct requires states to consider AMI and decide what makes sense. The appropriate way to do this is by examining the likely balance of costs and benefits for a given utility system. Costs and benefits fall into two possible buckets: those associated with utility operations, and those associated with potential customer responses to time-differentiated prices signals. This Guide describes time-tested approaches to evaluating costs and benefits in the first bucket.

In many cases, AMI makes sense based solely on net benefits estimated in the first bucket.

While the AMI process is ultimately about making technology choices, it is imperative that functional requirements be defined and valued before any consideration is given to specific technologies.

I. SUMMARY OF KEY PROVISIONS OF SECTION 1252

The following italicized discussion of the key provisions of the Energy Policy Act is drawn and heavily edited from pages 14 through 20 of an excellent “Briefing Paper” by the National Regulatory Research Institute entitled Implications of EPAct 2005 for State Commissions. The full text may be found at: http://www.nrri.ohio-state.edu/dspace/bitstream/2068/809/1/05-16.pdf. We have substantially condensed the NRRI text to narrow the focus to the technology implications of PURPA.

Smart Metering Statutory Provisions

The Act requires each electric utility to offer each of its customer classes, and provide individual customers on their own request, a time-based rate schedule. Prices in a time-based rate schedule change to reflect variations in the utility's wholesale costs of generating and purchasing electricity. Smart metering rate schedules enable the electric consumer to manage energy use and cost through advanced metering and communications technology. Several nonexclusive examples of smart metering are provided in the Act:

- Time-of-use pricing
- Critical peak pricing
- Real-time pricing
- Credits for peak load reduction agreements.

In looking at the smart metering standard, state commissions can rely, in part, on previous work and experience with time-of- use and demand-response rates. For example, time-based rates have been successfully implemented in programs around the country, including Georgia Power in Georgia, Duke Power in the Carolinas, Niagara Mohawk in New York, Gulf Power in Florida, and the Salt River Project in Arizona. California recently concluded its successful [as judged by some] critical peak pricing pilot program.

Time-based rates should reflect the benefits of avoiding generation, transmission, and distribution costs due to consumers switching from peak hours. These benefits would be measured by determining the marginal cost savings of these functions. Customer conservation or load shifting during peak period relieves transmission congestion and might make the importation of lower cost generation possible. Reviewing and deciding on a standard requires consideration of the costs and benefits of such programs. Most of the costs are in the form of metering and capital expenditures. These costs are likely to be borne by the customer. In deregulated markets the advanced metering might be offered by the marketer or perhaps by the wires company with a marketer offering the time-based rate schedule. Each state commission will need to customize its standard to its own regulatory situation.

The PURPA rate making standard dealing with deadlines for regarding the new smart metering standard may be somewhat confusing. The proposed regulatory standard, IF ADOPTED AS DRAFTED, would require utilities to provide a time-based rate schedule to any customer six months before the PURPA statutory deadline for the actual consideration of whether or not to require implementation of that ratemaking standard. This would appear to be unrealistic and confusing, until one realizes that the adoption of the PURPA standards as written is purely voluntary by the state regulatory authorities. States are free to reject the standard totally, or replace the implementation dates with those that reflect state regulatory authorities own priorities and schedule.

Potential DOE Intervention

Responsibility for consideration of the five new PURPA standards rests with state commissions. Nevertheless, the Secretary of Energy has discretion to intervene in any state ratemaking or appropriate regulatory proceeding.

Procedural Requirements

The process for developing standards is formal and likely to be relatively resource intensive. State commissions are to consider the standards after public notice and a hearing. The determination must be in writing, based upon evidence presented and available to the public. Some time and effort can be saved if the state has already done some groundwork. Prior state actions can substitute for the consideration and determination requirement, if before Aug. 8, 2005, the state has implemented the standard (or a comparable standard) for the utility; the state commission has conducted a proceeding to consider implementation of the standard (or a comparable standard); or the state legislature has voted on the implementation of the standard (or a comparable standard). However, in the case of the smart metering standard, consideration or state legislation must have occurred within the three years prior to enactment of EPAct 2005. States will need to get started on their proceedings in a timely manner. A state's failure to comply with the standard setting requirements triggers PURPA Section 112(c) which requires that the consideration and determination be undertaken in the first rate case proceeding commencing after the deadline.

State Discretion

Nothing prohibits a state commission from determining that it is not appropriate to implement a standard pursuant to its authority under otherwise applicable state law. State commissions, to the extent consistent with otherwise applicable state law, are to implement any standard that they consider to be appropriate, and they may say in writing the reasons for declining to implement any standard they consider inappropriate. The time frame for implementing a given standard (as distinct from making a decision about it by August 8, 2007) is controlled by the states. This is because the states have discretion to adopt a modified standard.

II. BACKGROUND & SELECTED DRIVERS

What Drove PURPA 1978?

In the late 1960s the electric utility industry thrived in a generally benign regulatory climate. Utilities often filed for rate decreases. This had been made possible by ever improving efficiencies in fossil-fueled generation. Efficiency increased due to economies of scale, low fuel costs ($1.66 per barrel of oil in 1966), comparatively benign environmental requirements, far lower costs to select sites with fewer required approvals, and a lower penetration of weather-sensitive loads (air conditioning) than became the norm in the decades to follow.

All that began to change in the 1970s. The Arab Oil Embargo of 1973-waiting in long lines at the gasoline stations during to buy the limit of 5 gallons of gasoline-brought home higher fuel prices and the realization of the nation's perilous dependence on imported oil. Policy makers and the public recognized that fossil fuels are a finite resource, a strategically sensitive resource. The precarious supply chain for imported oil was evident and brightly illuminated. The oil embargo sent many signals, loud and clear:

- National security is threatened when other countries use the supply or price of oil as a means of coercion.
- A vast transfer of wealth to the oil producing countries had begun.
- The US dependence on imported oil, rather than domestic production, was growing, year after year.
- Renewed emphasis on domestically produced fuels was imperative.
- The revaluation of energy that followed the 1973 oil embargo lead to an economy-wide imperative to increase energy efficiency.
- Conservation took on a new importance.
- Interest in renewable resources surged as a way to establish energy independence. Alternative technologies such as solar photovoltaic, solar thermal, biomass, wind, tidal, and other renewables became highly topical and politically fashionable.
- If a greater portion of electric load could be served by higher efficiency base load resources, including nuclear, coal and hydro, there would be less dependence on lower efficiency, oil-fueled peaking generation.

Not only had energy costs risen, but further improvements in generation efficiencies became more elusive. A bigger generating plant no longer assured incrementally greater efficiency. The expanding costs of required environmental improvements and pollution abatement added to the cost of new generating facilities. Fuel choice became more constrained by emissions constraints. Low sulfur coal and natural gas became preferred domestic fuels. In the late 1970s, events at General Public Utilities' Three Mile Island nuclear plant created a wet blanket that smothered domestic nuclear activity for decades to follow. Utilities began to seek rate increases.

Federal Initiatives in Reaction to the 1973 Arab Oil Embargo

In 1974 the Congress reacted to the oil embargo by forming the Federal Energy Administration (FEA), chartered to investigate policy and procedure. FEA eventually expired under the sunset provision that established it. One important FEA initiative was to explore the potential for time-of-use (TOU) rates to help reduce peak loads.

Later in 1974 the US Energy Research and Development Administration (ERDA) was formed to support the technology needs of the nation, including the ability of the then-emerging remote automatic metering systems to support innovative rate structures. ERDA was later rolled into a successor agency, the US Department of Energy (DOE). Electric utilities could see that the Federal Government was intent on grabbing the steering wheel for both policy and technology development. In reaction, the industry formed Electric Power Research Institute (EPRI) to create an industry-managed R&D activity. EPRI over the years funded valuable technology demonstrations and investigations into innovative rates, load control, demand response and remote automatic metering systems. The Energy Policy Act of 2005 traces some of its roots to these efforts.

Why TOU Rates Were Part of the Solution

Why were TOU and other peak load sensitive rates of interest to these agencies in the 1970s? Were there capacity constraints? No. US base load and intermediate load generation were fueled primarily by coal, nuclear, and Bunker C and other heavy fractions of the oil distillation process. But peak generating plants-diesel engines, small boilers, and aircraft derivative combustion turbine generators-used precisely the fuels provided by foreign sources, that is, the lighter fractions of the refining process. If peak load could be reduced there would be several benefits:

- Dependence on foreign fuels would be reduced since more of the generation mix would be supplied by base load and intermediate capacity, using less sensitive fuels.
- A higher percent of kWh would be produced by the more efficient plants, and less by the relatively inefficient peakers.
- The acknowledged low capacity factor of and dubious investment in peakers, which stand unused most of the year, would be reduced if fewer plants were required. Better utilization of existing or new peakers could be assured.

These considerations all suggested that time-differentiated rates would reduce peak load and become a promising tool for reducing dependence on foreign oil, recasting the US generation mix, and encouraging conservation and deployment of other energy resources. These concepts, and the related research that was done in the wake of the oil embargo, became cornerstones of the 1978 Public Utilities Regulatory Policies Act (PURPA). The Energy Policy Act of 2005 amends several provisions of PURPA.

What happened between PURPA 1978 and the amendments of 2005? PURPA established that within two years after November 9, 1978 each State regulatory agency and each non-regulated electric utility would commence consideration of the following rate and generation issues that impact energy consumption and develop appropriate standards.

- Cost of Service
- Declining block rates
- Time-of-day rates
- Seasonal rates
- Interruptible rates
- Load management techniques
- Integrated resource planning
- Investments in conservation and demand management
- Energy efficiency investments in power generation and supply

PURPA established that within three years after November 9, 1978 each State regulatory agency and each non-regulated electric utility would complete consideration of the standards. In the event that the State agency or non-regulated utility failed to comply, PURPA required the State regulatory agency or non-regulated utility to undertake consideration and make a determination of each standard in the first rate case proceeding that commenced 3 years after the November 9th date.

It is important to note that PURPA did not require adoption of these standards. It merely required that the State regulatory authority (with respect to each utility for which it has ratemaking jurisdiction) and each non-regulated utility consider each standard and determine whether it would be appropriate to implement such a standard to carry out the purposes set forth in Chapter 16 of the code. Accordingly, there was wide variation among the approaches taken by State regulatory agencies and the utilities whose rates were within their authority. Some states mandated Time-of-Day (TOD) rates and scrutinized the economic foundations of those rates. In other states, TOD rates were composed that were prominently disadvantageous to most customers and were scarcely promoted. This predictably resulted in low levels of initial participation followed by poor retention of those that did sign up.

Perhaps as importantly, free-ridership was not addressed by the selective use of TOU rates, the administration of fuel surcharge clauses, and the lack of prompt and specific feedback to customers so they could determine the impact of their consumption choices.

Technology Challenges to PURPA - 1978 to 2000

The technology available at the time of PURPA 1978 was a key challenge to implementing TOD metering for residential customers. The most prominent metering “tool” for residential TOD rates was the self-contained multi-register meter. This was a mechanically complex and comparatively costly meter. It had an internal clock that switched consumption among two or three different mechanical registers depending on time of day. Because these meters were expensive, and were more expensive to read manually, many utilities added a further “metering charge” of $4 to $8 per month to a TOD customer's bill.

A small and growing number of fixed network remote automatic metering systems were installed beginning in the late 1970s, but most of these systems were geared more to load control than to advanced metering.

The modern microprocessor became commercially available at low cost in the late 1970s, and electronic meters appeared that could be "probed" with an optical sensor to retrieve the data. Also, electronic registers were introduced that could be fitted into induction meters for special metering applications. A significant design challenge of the 1980s and early 1990s was how to preserve data stored in the meter when there was a power interruption. This either required battery back-up or use of early (and expensive) non-volatile memory that would retain stored data, even when power was absent. Batteries were especially undesirable for residential applications because of the large quantities of meters and the need to change batteries periodically. Batteries are still considered more acceptable in polyphase meters for commercial and industrial customers. Today, of course, we have very low cost non-volatile memory that can retain massive amounts of data for extended periods without batteries.

In the mid 1980s the Federal Communications Commission enacted rules that allowed commercial products to operate using formerly classified "spread spectrum" technology, unlicensed, in the 902 to 928 MHz band. Within a few short years companies like (then) CellNet, Enscan (later acquired by Itron) and others offered automatic meter reading systems based on fitting a half-moon shaped radio module into the available space in a typical single phase residential Watthour meter. Some systems captured transmitted meter data with a handheld receiver or a roving vehicle. These are still extremely popular, especially for water and gas metering, and are generally referred to as walk-by/drive-by products or as OMR (off-site meter reading). These products are, however, generally unsuitable for most innovative rate forms including most TOU, CPP and other dynamic rates.

Metering technology to support innovative rates evolved rapidly in the 1980s. Add-on devices were introduced to convert electromechanical meters into time-sensitive devices. In addition to these devices being retrofittable into electro-mechanical watt hour meters, meter manufacturers began developing electronic and hybrid meters with time-of-use functionality. Lower costs, higher reliability, and richer feature sets rode the wave of Moore's law.

The metering technologies of the 1990s benefited from electronic techniques that were first refined in commercial and industrial (C&I) metering and trickled down to residential metering. By the late 1990s, the major meter manufacturers were all well along in their development of low cost solid state residential meters. In the first few years of the new millennium, each meter manufacturer brought innovative, low cost, solid state meters to the marketplace. Thes developments have had a profound effect on AMI, where the close integration of the metrology, memory, display, computation and communications has evolved to a point not achievable with induction meters.

The uncertain prospects for industry restructuring, and the question of "who should do the metering?" cast a long shadow over the market for smart metering systems in the late 1990s. Utilities were understandably concerned about making major investments in advanced metering systems if there was a chance that these would become stranded investments. All sorts of independent meter data acquisition companies and meter data management entities were conceived to assume equal and open access to metering data to various market participants. This tumultuous period has now passed, and utilities large and small are now aggressively moving AMI into the mainstream of their operations.

Has the history of innovative rate structures tracked the technical evolution of the enabling metering technology? No. The EPAct of 2005 confronts this reality.

Many of the PURPA 1978-inspired voluntary TOU programs actually reached their zenith of participation in the mid 1980s, and then began to decline. One large utility in the Northeast reported a peak TOU participation of 26,500 customers in 1985, dropping to less than 100 today, 20 years later.

Why have so many utilities lost their enthusiasm for TOU rates? Why do so many utilities that have TOU rates available now have so little participation? Is it the rates? Is it the inconvenience of adjusting life to the utility's clock? Is it lackluster promotion by the utilities? Many utilities contend that their residential customers have very little enthusiasm for TOU rates. Others point to a “wear-out” sentiment that appears after a few years of dealing with more complex rates.

From a customer's perspective, at least five factors influence their view of TOU rates:

- Prices: How much can I save? How costly is energy during peak or shoulder periods compared with off-peak? How does that compare to the flat rate?
- Duration of peak periods: How long are the high priced periods? If the peak is just a couple of hours wide, it is obviously much easier to deal with than peak periods of 6-8 hours or more. So, is it reasonably convenient for me to make adjustments to consumption, or is it so inconvenient that it really isn't worth the bother?
- Understandability: Do I resent having to be mindful of the timing of so many aspects of daily life? Does this add complexity and uncertainty when I would rather be simplifying my life?
- Opportunity to control: Can I opt to use the higher cost energy?
- Feedback: What information will I get that helps me understand the choices I am making with respect to when and how much energy I use?

Customers that can respond to a TOU rate by shifting or eliminating some peak period consumption usually expect to save money, compared to what they were paying under the former “flat” rate. They know that getting this saving may involve some inconvenience or discomfort. Operation of the electric dishwasher or clothes dryer may have to be delayed until later. The air conditioning thermostat may be set higher. The pool filter pump may be on a timer. If, after a few years, the customer finds that all his effort, with all the added complexity to his already-complicated life, saves only a few dollars each month, he may decide that it simply isn't worth the bother. And if he gets lax in disciplining his energy consumption he may realize that he is actually paying more than he would on the “flat” rate. He drops off.

Many of the voluntary residential TOU participants in the 1980s were metered by special multi-register meters with an internal clock. Installation of this special meter sometimes created a higher monthly “metering charge” on the customer's bill. That charge often offset most of the savings the customer expected to get. Today's very capable advanced metering systems can implement TOU or other complex rates with relatively simpler metering. By applying such systems to all customers, special “metering charges” are avoided, and customers may come on or drop off TOU rates without any additional equipment or a service visit to the customer's home.

Many of the rates originally promulgated in reaction to PURPA 1978 still exist in some form. Accordingly, there is a large body of utility experience with TOU rates. Previous customer acceptance of those rates is a factor in how individual utilities and their regulatory bodies will react to the imperatives of the EPAct.

III. ADVANCED METERING JUSTIFICATION

The Imperatives to Action

While most businesses will typically invest in something as substantial as AMI only if it is economically attractive in the near term, regulated utilities have a broader charter and will consider other motives. The reasons to deploy advanced metering fall into three broad categories:

- Regulatory Direction
- Economic Value
- Customer Benefit

Regulatory Direction

Regulatory decisions may directly drive deployment of advanced metering independent of economic calculations. Regulators have many good reasons for directing utility actions, including fairness, value to the society as a whole (independent of the value to the utility), quality of service, and others.

Regulated electric utilities in the State of California are now responding to regulatory direction to submit plans for large scale AMI deployments, with full delineation of costs and benefit. This regulatory initiative is an aggressive and innovative step, seeking to promote customer awareness of peak load periods and response to peak-sensitive pricing in order to reduce the likelihood of a repetition of the rolling blackouts of year 2000. The deployments will not go forward independent of economic implications, but the primary driver is only partly economic. It is policy, developed in a consensus process with legislators, utilities, regulators, businesses and consumer advocates.

PURPA is similarly a policy statement motivated by the broad interests of America as a whole. Some regulatory bodies and utilities will decide to pursue peak sensitive pricing and demand response aggressively, depending upon their perceptions and circumstances. Others will find that the policy objectives already are met or are otherwise not applicable. Local conditions will drive the decisions deemed best for customers. Many utilities, without any regulatory imperative, will continue deploying AMI systems simply because they reduce costs and improve the quality of service to consumers.

Customer Benefit

Regulated utilities traditionally operate as monopolies with an "obligation to serve" for the benefit of shareholders and customers. AMI typically produces a significant financial benefit, but that benefit may not adequately justify a system on a purely economic basis, as discussed below.

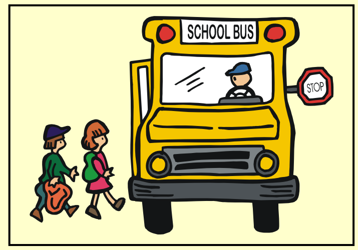
AMI systems provide dozens of benefits to customers that are real but not readily quantifiable. These include more rapid resolution of disputed bills, fewer errors, improved response to outages, reduction in theft losses, improved security through elimination of intrusions by meter readers and access with customer-provided keys to indoor meters, off-cycle meter reading, customer-selectable billing and payment dates, and others. These benefits are discussed in Customer & Societal Benefits starting on page 12.

Economic Value

Whatever the principal motives, a utility will almost always examine the economic value of AMI before committing to a deployment. Even if the principal motive is non-economic, the utility needs to project the financial consequences to the organization of such a large capital expenditure. The conventional approach to projecting the economic value of an investment is to assemble a "business case." AMI systems have many capabilities. For any given utility, some of these capabilities will be highly valuable and others will be non-applicable. The business case reveals which capabilities have the highest value. Those high-value capabilities then become the requirements that guide the technology selection process. The business case should always precede any serious consideration of a specific technology or vendor.

A Tool for Calculation

A simple four-function calculator allows an elementary school math student to analyze a problem at a high level, without bogging down in the mechanics of calculations. This facilitates the student's insight into the problem.



In the same way, a capable and coherent business case allows the utility AMI team and top management to develop insight, to assess the value of specific applications, to do "what-if" analysis, and to compare various vendor and technology alternatives.

What is a Business Case?

A business case is a calculation that quantifies the costs and benefits of an investment over time. It supports the decision of whether and how to make the investment. The output of the business case is a measure of the value of the investment. Typical measures are the net present value (NPV) of the investment and the internal rate of return (IRR). Utility management may often require additional calculated measures for a complete assessment of the value of AMI.

A complete and capable AMI business case includes a "model" of the expected AMI deployment that allows the utility to experiment with and compare alternatives. Each potential application or source of value is fully developed with the participation of the experts in that application. For example, if the outage detection and outage recovery capabilities of representative AMI systems are assessed, the personnel responsible for outage management must be involved with developing that element of the business case. And so it goes with every other element of the business case. In the end, the benefits that would accrue to each type of AMI systems are rolled up, and we are able to see just how the benefits compare.

The model may be implemented with proprietary software, or with commonly used spreadsheet programs such as Microsoft Excel™. Where input values are subject to uncertainty, exercising the model for various assumed values of input parameters provides insight into the sensitivity of the investment result to those parameters, and the robustness of the overall conclusions. Such parameters typically include:

- Candidate AMI system(s)
- Meter population equipped with AMI (single phase, polyphase, both, etc.)
- Speed of deployment
- Cost of capital

- Inflation
- Customer response to new rates or demand response programs
- ...and many others.

The business case also supports numerous essential management processes after the AMI decision. It documents the expected benefits and costs, and becomes a reference by which actual project performance is measured. It allows detailed planning for rate purposes. It provides the basis for detailed regulatory dialog when needed. As the AMI deployment proceeds-generally over several years-updates to the AMI business case support project review, re-funding decisions, expansion or re-direction as budgets, management teams, and other circumstances change.

Key Business Case Attributes

The business case model must not only show the investment performance of the alternative AMI systems considered, it must do this in a way that also:

- Is *transparent*, that is, easily understood by, and answers the questions of, management, regulators, utility staff, and subsequent users (the AMI team staff).
- Is easily *revised* (or re-affirmed) a year and more later, perhaps by users other than those that constructed it.

Transparency

A business case for a major technology investment like AMI can be very complex. Nonetheless, it must be possible for the AMI team to show the business case results-and explain the business case-to numerous audiences in a way that allows the audience to see the assumptions, the relationships, the benefit elements, the cost elements ... all the structural and numerical elements of the business case.

Utilities are traditionally conservative for very good reasons related to regulation and the public need and expectation for reliable service. AMI is a large investment with sweeping operational consequences for the utility. Therefore, a decision to invest in AMI must be defensible in every way, for it will be scrutinized repeatedly at every level of management and regulation.

The business case is the central tool for responding to the questions such scrutiny will foster. It is necessary that an audience of senior management, board of directors, regulators, or operating management be able to test the assumptions in the business case and satisfy themselves that it is valid from their own viewpoint. Any of these parties can veto the investment. A complex business case that leaves the audience unsure whether they've had “the wool pulled over their eyes” will make it harder for those with veto power to refrain from exercising it. Transparency is required to overcome their legitimate hesitancy to approve the AMI case.

Revision

Because the AMI project involves large multi-year budgets, the project will likely be re-examined each year as other budget priorities arise. The AMI team will be called upon to explain the investment consequences of, for example, increasing next year's project budget by 10% and reducing the project schedule by a few months.

It won't be enough to say, “This will improve the investment performance.” It will be necessary to show how much because others will be advocating competitive opportunities in which to invest that money to genuine good advantage for the utility and the ratepayers. Distribution automation, call center automation, improved billing systems, and myriad other investments will vie for the AMI budget dollars every year. Each of them will have committed advocates, and for good reason, because each of them will produce verifiable benefits.

Producing a good business case is a significant effort. The AMI team won't have time to do it again each time the budget is called into question. The better approach is to “do it right the first time” by creating a business case that the AMI team can repeatedly revise with then-current figures to re-calculate the investment performance for the remaining life of the project.

Benefits

Identifying the full range of operational benefits that modern AMI systems provide is a demanding and time-consuming process. Why? Because these systems typically produce operating benefits that reach into almost every operating department of the utility. For example, these systems aid in outage detection and restoration, provide precise load data on each piece of distribution apparatus, improve customer satisfaction through better accuracy and timeliness of meter readings, aid in detecting energy theft/current diversion, reduce the number and duration of call center inquiries, and provide high resolution consumption data to those customers who are interested.

All these benefits accrue not only to the utility, but also to the utility's customers as improved service and moderated rates. Further benefits provide value to the customers and to society at large while having no value to the utility. This section discusses the benefits of AMI in three areas:

- Customer & Societal Benefits
- Traditional Utility Operations
- Electric Supply Operations

Customer & Societal Benefits

AMI benefits to customers are difficult to value and therefore often do not appear in the business case. But they deserve consideration by the utility and by regulatory decision makers. The following paragraphs discuss AMI benefits for which the value is subjective but, taken altogether, can be substantial.

Customer Service

AMI enables the utility to provide significantly better customer service. The first and most pervasive improvement is accurate and timely bills, with almost no estimated readings. But there are many others. For example, utilities with AMI commonly save daily readings from all meters. When a customer calls to question a high bill, the customer service representative can view a consumption history on the screen and observe that, say, “In the second week of that month your usage was about double your usual level. What happened that week?” The customer remembers that the foot valve in his domestic water well failed and the pump short-cycled for a week before he finally got it repaired. He realizes that his electric usage is related to his water usage, and that the bill is fair. And he appreciates the insight the utility has given him into his home operations.

Another example relates to outage detection. If the utility can know when and where outages occur, it can notify customers who wish to be notified. For example, if the power fails at my elderly mother's house in another town, she won't be able to cook on her electric stove. My utility can let me know and I can go take her out for dinner. This is good customer service. If my business has an unmanned warehouse in another town and the refrigeration unit stops because the power goes out, the utility can let me know and I can arrange a generator to protect key inventory. This, too, is good customer service.

Other examples are too numerous to recount. But the data provided by AMI are a substantial resource the utility can use to better understand customer behavior and provide data and services to customers.

Fairness & Privacy

Some utilities have worked closely with builders for many years and arranged that essentially all meters are outside and near the front of the property, easily reached by the utility meter reader. But this is not the norm. Meter readers commonly must go around to the back of the house, into the dog's fenced area, behind the foundation planting bushes, and other inconvenient places to read the meter. It's inconvenient for the customer, too. The requirements to keep the dog in on the 14th of the month, or let the meter reader into the basement are all nuisances that customers find increasingly annoying as more of them are working during the day.

Businesses, too, benefit from AMI. Particularly at businesses with security issues, admitting the meter reader to the electrical service every month is a distraction that costs money. Alternatively, allowing the meter reader to carry a key is a security risk many businesses would prefer not to take. Many meter reading departments keep thousands of keys to customer premises, and key management is a significant problem and risk for the utility.

> AMI eliminates the need to send a meter reader to the customer’s meter, solving all related access, convenience, security and privacy issues.

A saturation AMI deployment produces a fairness benefit that can be notable. Traditional induction meters (that is, electro-mechanical meters, with a spinning disk) can slow down very gradually as they age. Most regulated utilities are required to audit a portion of in-service meters annually to measure meter accuracy. When meter families are excessively inaccurate they are routinely removed. However, some families may be within the permitted accuracy tolerances and still under-register consumption. Overall meter plant accuracy of about 99.7% is typical. That is, the meters under-register consumption by about 0.3%. This varies from utility to utility, but 0.3% is typical. This under-registration is less than $10 per year for most residential customers. This is so small that it is not cost-effective to change the meters just to fix it. But the AMI deployment changes every meter anyway, and brings aggregate meter plant accuracy very close to 100%. If the meters used for AMI are electronic (rather than induction), then this fairness benefit will be enduring because electronic meters have no mechanical wear or friction and do not slow down over time.

A final fairness benefit is meter loss reduction related to causes other than accuracy. These causes are energy theft, meter installation problems, and meter failures. This benefit is larger than the meter accuracy fairness benefit, and is easier to value, but has some uncertainty. Few utilities know how much energy is lost to theft and meter problems. Various studies have indicated losses as high as 3% of revenue in North America.

A 2001 study1[1] sponsored by EPRI found that the losses are more likely lower than that, around 1% or less. Of this amount perhaps half is due to meter problems and failures; the other half is due to theft of service. A high fraction of the meter problems and nearly all of the failures will be remedied by a competent AMI deployment that re-installs all meters. If the deployment includes inspection of each meter installation for evidence of tampering and diversion, then this, too, will produce a benefit to customers. Finally, for the life of the AMI system, the AMI-equipped meters will detect and report some kinds of energy diversion and meter tampering to the utility.

Such reductions in meter losses benefit the utility financially until the next rate case readjusts rates to account for these (and other) consequences of AMI. But the enduring benefit goes to ratepayers as the elimination of the $5 to $50 per year that honest businesses and consumers pay to cover meter problems and energy theft by others.

Some argue that AMI may increase energy theft due to the loss of “eyes in the field” when meter readers no longer visit every meter every month, notwithstanding the tamper detection mechanisms in modern AMI systems. True, AMI will not specifically detect and report some kinds of theft, such as taps ahead of the meter. But AMI often involves retrieval of daily or hourly consumption readings, and this added information (compared with prior once-a-month readings) can provide useful insight in identifying locations where theft is occurring. The existing level of theft has occurred even with manual readers in the field. We don't agree with entirely eliminating “eyes in the field.” It is good practice to randomly visit and inspect each meters on some recurring basis. Some utilities plan such inspections on a roughly five year cycle. What about other benefits? Some advocates of manual meter reading have cited the value the manual meter reader as a recurring and visible utility presence, even noting incidents where meter readers have saved lives by observing threatening situations. But many more would argue that the intrusive presence of the manual meter reading on a customer's property is a costly and obsolete artifact of history.

Electric Service Quality

Electric load data are a mainstay of distribution engineering, defining the base level of service the distribution system must support. Utilities traditionally rely on instrumentation in substations (including SCADA2[2]), engineering studies, and statistical data samples to quantify electric load in different segments of the distribution system. Substation instrumentation often keeps an exact hourly load profile for each feeder, but much of the data for smaller distribution segments is estimated.

AMI meter data provide a quantitative basis for knowing distribution loads, instead of estimating them, allowing engineers to more accurately size equipment and protection devices, and to understand distribution behavior. Some utilities report they have improved quality of service and reliability as a result.

Many AMI systems notify the utility when a meter experiences a service outage and when power is restored. This function supports more rapid and efficient restoration efforts by utility crews, further improving service quality.

[1] *Revenue Metering Loss Assessment*, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC, and Baltimore Gas & Electric Co. Baltimore, MD, 2001. 1000365

[2] Supervisory control and data acquisition

In addition, the demand response capacity of AMI systems offers further service quality improvements through reduced congestion in power lines and more balanced transmission and distribution load management.

Reliability

In the summer of year 2000, California's Independent System Operator implemented rolling blackouts to avoid system collapse as electric demand approached available supply. The direct costs (e.g. power costs) have been variously estimated at tens of millions of dollars. Estimates of indirect costs (e.g. business and consumer losses) range to 1,000 times higher. Many have argued convincingly that a modest demand response capability would have avoided the need for such drastic action, producing a societal benefit in the billions of dollars. The societal dislocation associated with interruptions of a resource as essential as electric supply has been a significant motivator of policy and is reflected in the EPAct 2005[3]:

It is the policy of the United States that 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, shall be encouraged, the 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 service markets shall be eliminated.

Advanced metering is a pre-requisite for fair and effective demand response. It enables the utility to measure how much each customer uses during demand response events, so that each customer pays and/or benefits according to consumption. AMI systems with customer notification and demand management elements can accomplish the above objectives. Evaluating their costs and benefits is a significant challenge. The remainder of this section of the Guide discusses how to do this.

Macro Benefits

Other reliability benefits of AMI and demand response are more certain and more practical to estimate. Examples include:

- Improved efficiency of societal energy use
- Favorable environmental impact
- Lower user costs, which may produce an overall benefit to consumers and the economy, particularly in a time of rapidly rising energy costs

Utility business cases generally do not include these benefits because they do not improve utility operations or otherwise result in lower electric rates. But it may be practical and constructive for regulatory policy to assign some value to them. One widely expected mechanism is that emissions trading credits may turn the favorable environmental impact into dollars for the utility, while providing the environmental benefit to the society at large.

Demand response produces a clear benefit in reduced supply cost that is readily estimated if the analyst can predict consumer and business behavior during demand response events.

[3] Energy Policy Act of 2005, Subtitle E, Section 1252 (f)

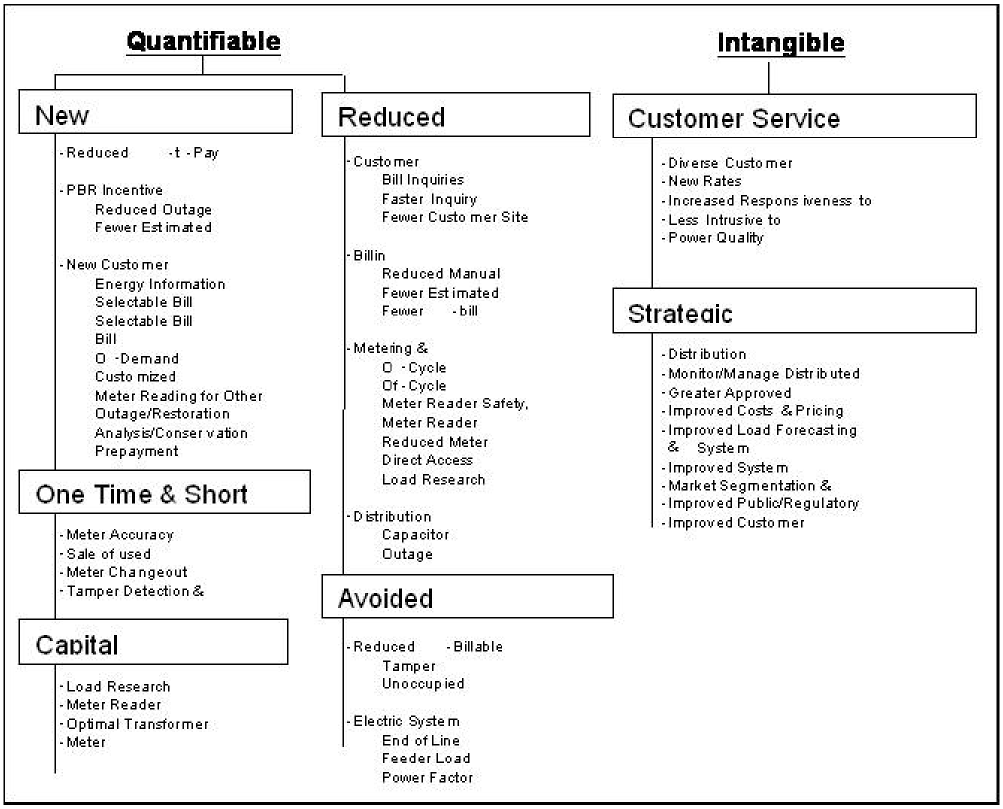
Traditional Utility Operations

The original and clearest motive for automating meter reading is to reduce or eliminate the labor expense of manual meter reading while improving the accuracy and completeness of monthly billing. When the vehicle, training, health insurance, and other overhead expenses of manual reading are included, reducing or eliminating manual reading is often the largest single AMI benefit. It typically constitutes one third to two thirds of the total AMI benefit[4] in traditional utility operations.

Other AMI benefits enhance utility operations and can produce value exceeding the meter reading value. Figure 1 below shows examples of these utility operating benefits. This categorization of benefits is just one of many ways to portray this subject, and many readers will reasonably disagree with it. For example, the very first benefit shown at the top left, Reduced Read-to-Pay Time, can also be correctly shown as a Capital Reduction benefit rather than a New Revenue benefit. The shorter read-to-pay time advances the utility's cash flow by a day or so, creating a one-time revenue influx. This effectively reduces the utility's need for working capital. But some utilities choose to include it in the business case as “revenue” equal to the recurring interest on that capital. By whatever name, the overall point is that AMI impacts are broad and substantial throughout the utility and constitute significant enhancements to routine utility operations.

[4] As a corollary to this, a utility can make a very quick *and coarse* estimate of the AMI benefits by multiplying by about 2.5 the total cost of its meter reading activity. Note that this estimates the benefit in traditional utility operations only. Other benefits are additional, such as demand response.

Figure 1: AMI Benefits in Traditional Utility Operations

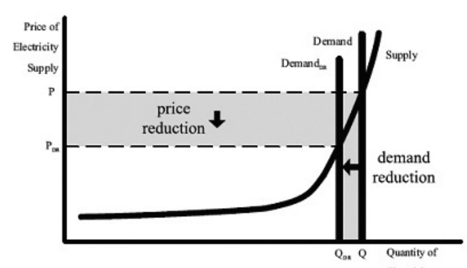


Examples of the details of the above benefits are discussed in *Estimating the Benefits* starting on page 20.

Electric Supply Operations

The demand management benefits of AMI have been widely discussed in public forums since the rolling blackouts in California in 2000. The term "demand response" has come to mean actions by energy users in response to electric market dynamics. The principal benefit of demand response is that, during periods of high energy demand and price, a small reduction in demand produces a relatively large reduction in market price. This concept is illustrated qualitatively in Figure 2[5] below.

Figure 2: Primary Demand Response Benefit



[5] *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*, DOE report to Congress pursuant to EPAct 2005, February 2006. See http://www.electricity.doe.gov/documents/congress_1252d.pdf.

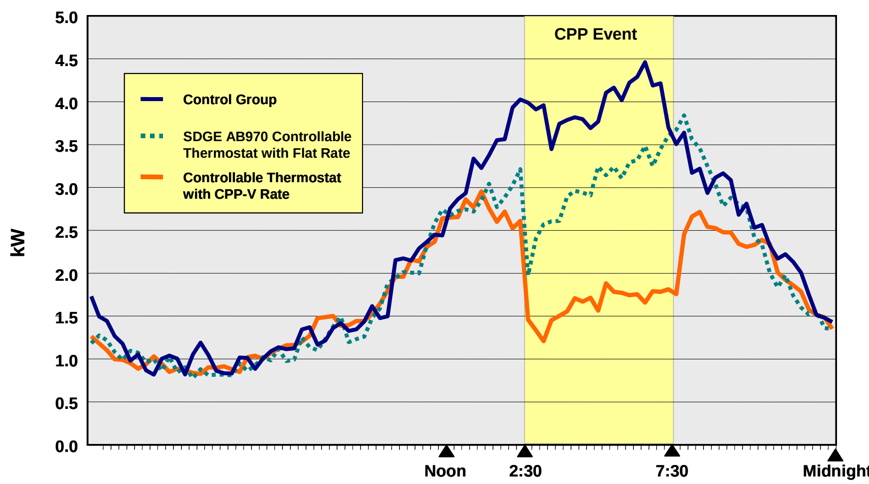
Price and demand reductions during high-demand periods benefit the utility in many ways, including:

- Reduced peak capacity requirements
- Reduced congestion costs
- Reduced T&D costs
- Reduced generation costs
- Reduced potential for market influence by any one supplier
- Improved electric system efficiency (lower operating costs)
- Improved electric system reliability (lower maintenance costs)
- Greatly facilitated settlement data management

Electric market settlement commonly is not completed until 30 days or more after the energy delivery occurs. AMI allows a utility to gather settlement data much more quickly and accurately. If the regional settlement process supports a faster resolution, AMI reduces the utility's capital costs by reducing the "float" time associated with the long settlement process.

The State of California conducted a statewide pricing pilot (SPP) to test the willingness of consumers to respond to varying market prices and estimate the benefits of such demand response. The study[6] involved about 2,500 randomly chosen participants in various climates, economic strata, and other pertinent categories. Participants received electric service under time-varying electric rates, including critical peak pricing (CPP) rates that applied a high price when the electric market was under stress. The results convincingly demonstrated that, at least in the short term, consumers are willing to make substantial reductions in response to such rates. Figure 3[7] below illustrates one example of demand reduction from the SPP.

Figure 3: Actual Residential Critical Peak Impacts



[6] *Statewide Pricing Pilot Summer 2003 Impact Analysis*, Charles Rivers Associates, August 9, 2004.
[7] *Statewide Pricing Pilot (SPP): Overview and Design Features*, presentation by Roger Levy, Levy Associates, at a joint workshop titled "Advanced Metering Results and Issues", Sacramento, California, 30 September 2004.

The impact (up and down) of the CPP rates on the customers' bills averaged about 5% for residential customers and about 10% for business customers[8]. Some paid more, others less, but the dramatic benefit to the electric system shown in Figure 3 was produced with a relatively small overall impact on bills.

Converting the demand reduction benefits into dollar value in a business case requires many assumptions about future energy prices and market conditions. One relatively simple approach is to use past market data as a proxy for future market behavior. A complex approach-which may be no more accurate-involves risk valuation methods and probabilities of occurrence for various market event scenarios.

Depending on the utility operating scenario and assumptions, the aggregate benefits of demand response can be greater or less than the AMI benefits in traditional utility operations. If one includes in the demand response benefit the avoided costs and consequences of rolling blackouts, then demand response benefits may be many times the operating benefits, and also many times the cost of the AMI and demand response system. As importantly, benefits accrue to constituents outside the utility such as the rate-payers. The EPAct suggests that these benefits be assessed and considered even though they may not impact the return on investment as measured from a strictly utility perspective.

What Is the Downside of Meter Automation?

The paragraphs above describe AMI benefits for customers and society, and utility T&D and supply operations. Readers may reasonably wonder: Is that the whole story? Are there no negative consequences of AMI?

Certainly, traditional meter readers threading through the service territory have produced many positive benefits. Anecdotal stories abound relating how a meter reader helped a fallen elderly person, discovered an incipient house fire, reported a serious electrical hazard in a service drop, and performed other socially valuable actions. If meter readers no longer follow their appointed rounds, who will be there when the need arises? And how will we discover meter tampering and other energy thefts when meter readers no longer give us "eyes in the field"?

Some of these items are hard to respond to with certainty. Perhaps some one else will come along and discover the fallen elderly person, or the incipient house fire. But it is unlikely that others will be as quick to notice a hazard in the service drop or discern and report meter tampering. On the other hand, AMI will allow the utility to detect some distribution problems that, in the absence of AMI, will degrade to failure before the utility can know about them. And it isn't clear that meter readers are effective at discovering meter tampering. Two investor owned utilities that checked for meter tampering when deploying AMI reported that 0.3% to 0.5% of meters showed evidence of tampering that had not been reported by meter readers.

Plexus advises utilities with AMI to plan and execute a meter site sampling program to annually examine enough meters to monitor whether energy theft is rising. Such a program can be integral to other field activities that occur for other reasons, such as collections, new meter sets, distribution work, etc. The other "benefits" of manual reading may be lost. But the positive benefits of AMI are very substantial will far outweigh the loss of manual reading, which often rely on chance.

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[8] Ibid

Estimating the Benefits

- Utilities have used many approaches to creating the AMI business case. Following is a basic approach used by consultants to the industry that has worked very well for many years. Its most important outputs are:
- A quantitative portrayal of the balance of financial costs and benefits AMI will constitute for the utility and its customers.
- A unified team of individuals who understand AMI benefits, what they are worth, and what organizational and process changes are needed to realize them. This core team will lead the effort to acquire AMI and maximize the value it produces.

This section describes the process of estimating AMI benefits.

Kickoff

The utility assembles a team of representatives from all affected operating activities in the utility. This normally includes metering, meter reading, customer service, distribution engineering, distribution operations, telecommunications, information technology (IT), system planning, rates, and regulatory relations. If the business case is to include benefits related to electric market operations (e.g. demand response), then the team will also include representatives from electric procurement and marketing, supply operations, and settlement. The Team will need a leader, of course, an individual with good communication, project management, and coaching skills who coordinates the efforts and gathers the results into the business case.

The AMI team will need a good grasp of the capabilities and limitations of the AMI the utility is considering. Usually, the utility will have been following AMI for some years and some of the staff will be very well informed. These staff members, or other experts, will kick off the business case effort with a tutorial class for the rest of the team. This brings every one “up to speed” on the important features and issues of AMI systems and applications. This tutorial is important. The ability of the AMI team to estimate benefits and costs will be heavily dependent on the members' understanding of the subject.

Executive Sponsorship

It is extremely helpful (arguably, necessary) for the AMI team to have executive charter and sponsorship. The process of exploring and selecting an AMI system will challenge mid-level managers throughout the utility to estimate the amount of their consequent budget reductions. Everyone is understandably reluctant to find ways to reduce the scope of his own job. If the executive demeanor is collaborative, direct executive involvement in the working sessions will motivate everyone to keep the utility's and its customers' best interests in view. This generally produces high-value results:

- The estimated benefits are larger.
- Because the executive is there to both challenge them and support them, team members develop more realistic and well-defined plans for achieving those benefits.
- Team members take the process very seriously and, when the day comes to actually deploy the system, they know how to do it and how to extract the predicted benefits.

Utility AMI teams without executive leadership tend to focus on shorter term strategies and benefits, and to find a lower total value of AMI benefits. Many utilities have chartered an AMI team, studied AMI, and concluded that AMI is uneconomic for them when more senior leadership would have led to a different result.

In addition, an AMI team without executive leadership has more difficulty preparing for and conducting the needed meetings with senior management. This hampers the decision process and has resulted in some program failures.

Initial Estimates

The AMI team conducts brainstorming sessions to identify new ways the utility can operate to take advantage of the AMI system, and then does the detail work to estimate the financial impacts of the change. The process starts in AMI team meetings, and continues as individual team members work in their departments examining the details of existing business processes for opportunities to exploit AMI capabilities and data. It is helpful to include in the process individuals with experience identifying and quantifying AMI benefits.

Typically, AMI team members will find and estimate some benefits that the team will later judge to be overstated. Conversely, the team will decide that some of its early estimates are too conservative and should be increased. The important point is that the team members must vigorously engage in the effort, and apply their best combined creativity to discover the changes to current operations that can best take advantage of AMI to produce benefits. This will involve investigations into current business processes and resources, and exploratory conversations with many managers in the utility about how it can operate differently, and better!

The importance of the team leadership and the tutorial quickly becomes evident. The team leadership must inspire the team-almost evangelize-to believe in the potential of AMI. But it must also adhere to a rigorous and practical recognition of what realistically can be achieved. Executive participation is valuable in providing informed guidance on what resources can be made available to achieve the projected savings.

An Example Estimate

Each benefit estimate must identify and quantify the benefit, of course, and the costs of achieving the benefit. The cost of the AMI system is part of that cost. It will be separately estimated. But any non-recurring labor, capital, and operating/maintenance (O&M) costs of creating and sustaining the benefit must be recognized and cited. The AMI team will identify all these elements as it analyzes the benefit opportunities and makes the estimates.

Figure 4 below illustrates an example benefit estimate[9]. It shows the AMI benefit of savings in the handling of customer bill inquiries by phone to the residential call center. It is documented in a Microsoft® Excel® spreadsheet that automates the computations. Input data are shown at the bottom of the page. Green shading

[9] This example is fictional. It was assembled by Plexus Research using data from several utilities, normalized for size and type (electric, gas, water). Any apparent relationship of this example to any actual utility is purely coincidental.

indicates that the values are used in multiple calculations throughout the Excel® workbook and are drawn from other worksheets. Blue shading indicates that the data are entered on this page; they are used only on this page.

The benefit is explained in the AMI BENEFIT DESCRIPTION paragraph at the top of the page, and its value is calculated in the center of the page. For example, line 1 shows that the residential customer call center receives 900,000 calls per year. Line 2 notes that 35% of these calls are about the bills (other calls are about new services, disconnections, etc.). Line 3 calculates the annual number of calls related to bills by multiplying line 1 times line 2, and this arithmetic operation is cited in the text of line 3 as (1 - 2).

Other data are entered similarly, and intermediate values are derived, with all arithmetic fully explained. Note that numerous values are used that can later be updated, particularly those in green shaded cells.

Other call center benefits are estimated and documented on other sheets. For example, savings related to requests for special reads (move in/out, etc.) are separately documented, including elimination of the paper work ticket and related handling, and also including software development cost to enable the call center operator to electronically schedule in the AMI system a meter reading at a specific date and time.

The exposition of the estimate shown in the figure makes it plain to any reader-even years later-how the values are calculated. A separate text document explains the assumptions, source data, and any other basis of the estimate. At the bottom of the page, the ADDITIONAL REFERENCES section lists additional sources and references, if any.

Every benefit estimate must identify and quantify the costs the utility must incur to obtain that benefit that are not paid to the AMI vendor. These costs are shown and described in the NON-AMI COSTS section of the benefit estimate. (The direct purchase and installation costs of the AMI system are included in a separate section of the business case. The overall structure of the business case is explained in the Section titled *Assembling the Model*, starting on page 23.) Non-AMI costs include the utility's own IT costs, outside integration contractors, additional computing hardware, management consulting, etc. In the case of the example of Figure 7, the non-AMI cost is the labor by the utility's IT staff to create a real-time interface between the call center computing system and the AMI system. This allows call center operators to retrieve on-demand meter readings. The value of this labor is not cited here, but rather is estimated along with related costs on a separate Interactive Interface sheet that is identified here.

Similarly, each benefit estimate must identify and quantify any capital costs and O&M costs not paid to the AMI supplier. In this example, no other capital or O&M costs are incurred to create or sustain the Bill Inquiries benefit.

The total annual labor saving of $109,794 is shown on line 15, and replicated above in the yellow cell near the top of the page. The yellow shading indicates that this cell is the result of the entire page of information, and is used elsewhere in the workbook. It is transferred to the summary page where the calculation of key metrics begins.

Figure 4: Example Benefit Estimate

	Residential Call Center				
	Bill Inquires				
	AMI BENEFIT DESCRIPTION				
	An AMI system will result in shorter bill inquiry calls due to more accurate statistics on customer energy usage. This estimate assumes no reduction in call volume (based on Puget data), however a reduction in call duration for 50% of the calls is estimated. The average call lasts 6 min. (from call typing reports), with an actual problem discussion time of 3 min's per call. The rest of the call is getting the customer's personal info, accessing their file, etc. Of that 3 min's, a 1 min (33%) reduction is assumed. To achieve this benefit, the system must have an on-demand read feature w/response time of less than 30 seconds.				
			Annual	1-Time	Non AMI
	Amount of benefit (cost) estimated on this estimate sheet:		$109,794		
	AMI VALUE ESTIMATE	Amounts	Result		
1	Annual number of calls to Customer Call Center	900,000			
2	Percent of calls that are bill related	35%			
3	Annual bill-related calls (1 × 2)	315,000			
4	Est. percent of calls that would benefit from AMI (less time)	50%			
4a	Fraction of all meters equipped with AMR	100.0%			
5	Number of calls that would benefit from AMI (3 × 4 × 4a)	157,500			
6	Estimated time reduction per call, in minutes	1			
7	Annual labor hours reduction (5 × 6 ÷ 60 mins/hr)	2,625			
8	2005 hourly direct labor rate for Call Center Specialist	$22.50			
9	Annual direct labor saving due to shorter bill inquiries (7 × 8)	$59,063			
10	Employee benefit factor for Call Center Specialist	1.7			
11	Annual fully loaded labor benefit (9 × 10)		$100,406		
12	Indirect surcharge for Call Center Specialist	85%			
13	% of Call Center Spec. indirect surchage applicable to cost/savi	11%			
14	Savings in indirect costs (11 x 12 x 13)		$9,388		
15	Total annual labor savings due to shorter bill inquiries (11 + 14)		$109,794		
	NON-AMI COSTS				
	Description				
	A real-time interface between the Call Center systems and the AMI system is required to allow Call Center operators to acquire an on-demand meter reading. The cost for this interface is included in the estimate titled Interactive Interface.				
	Non-AMI Capital Costs	none			
	Non-AMI O&M Costs	none			
	INPUT DATA				
16	Annual number of calls to Customer Call Center	900,000			
17	Percent of calls that are bill related	35%			
18	Est. percent of calls that would benefit from AMI (less time)	50%			
19	Estimated time reduction per call, in minutes	1			
20	2005 hourly direct labor rate for Call Center Specialist	$22.50			
21	Employee benefit factor for Call Center Specialist	1.7			
22	Indirect surcharge for Call Center Specialist	85%			
23	% of Call Center Spec. indirect surchage applicable to cost/savi	11%			
24	Average annual hours worked per Call Center Specialist	1,796			
25	Fraction of all meters equipped with AMR	100.0%			
	ADDITIONAL REFERENCES				

Review & Edit

The process of identifying and estimating benefits described above takes several weeks, or months. To some extent, this time is needed for people to get comfortable with even enthusiastic about, the extensive operating changes the AMI system will bring. Rushing the process precludes this adjustment, and limits the ability of the team to foresee the best paths to obtaining the benefits.

Benefit estimates are reviewed by the team, and this almost always identifies added benefit opportunities and insight. It is crucially important that the benefit estimates are reviewed by the managers of the affected areas. When the process is done and the AMI team is presenting the results to the senior management, the CFO may turn to, say, the VP of customer service and say, “Do you concur with this estimate?” If the VP of customer service doesn't get an affirmation from his or her most senior manager, the process will be sent back to the drawing board. The costs and consequences of an AMI investment are large and will get extensive scrutiny. Management review during the process is essential for success.

Documenting Estimates

The spreadsheet shown in Figure 4 is one way to document the benefit estimates. This approach has several advantages.

- It uses commonly available software that most utility staff can operate easily.
- It is easily revised, months or years later (partly because everyone is familiar with it).
- It does not tie the utility to a specialized software firm or consultant, facilitating quick-turn-around analyses to support decision making.

A typical utility AMI business case may include 30 to 50 such estimates, each documented by an Excel® page(s), and a text document with backup description and source references.

Clear documenting of estimates supports the subsequent steps necessary to the AMI deployment. These include review by the utility senior management and board of directors, review with regulators (sometimes including public examination), detailed planning for the process of achieving the benefits, and tracking that process as it occurs. Finally, the clarity of documentation enables the utility to look back after the deployment is complete and determine if the benefits have been realized. Most will have been realized, some will not, and new benefits will have appeared. Every one of these is an opportunity to better understand how the utility operates and to further improve it.

Costs

When including AMI costs in a business case, it is important to include all the costs. The largest and most obvious cost is the amount paid to the AMI system provider(s). But other costs will affect the business case as well. Costs include:

- AMI system hardware & software
- New meters, and meter-related utility equipment and labor (e.g. calibration) for both new and re-deployed meters
- Installation management and labor
- Project management by outside contractor (or allocation of internal funds for project management by utility staff)
- IT integration by outside contractors (or allocation of internal funds for IT integration by utility staff)
- Utility internal costs, such as for facilities, project management, distribution equipment, installation labor, or additional IT support and integration

When including costs in an AMI business case, it is important to assure that corresponding benefits are included as well. For example, AMI IT costs are usually offset to some degree by avoided IT costs related to manual reading, typically including IT support for handheld terminals and related license and software maintenance fees.

Costs for meters and meter communication systems have been declining slowly for many years, reflecting the general decline in electronic product costs. At this time, costs for automated remote meter reading (that is, not including demand response functions such as customer signaling, load control or other demand response equipment) are approximately $100 to $175 per meter, including meters, all installation, and integration only with the monthly billing process. These figures are shown in Table 1 below. Values for walk-by/drive-by meter reading are shown for perspective.

Installed costs for demand response components vary widely and may be from $100 to $350 per site for signaling and control of a first load, plus about $100 per additional load managed. (Note that traditional direct load control is less expensive, but does not give the customer a role in the control, and is not considered "demand response" in the context of the EPAct.)

Table 1: Approximate AMI System Costs

AMI System Type	Cost ($ per meter)
Walk / drive-by (radio)	$50 - $90
Radio fixed network	$100 - $160
Power line fixed network	$110 - $175

Notes

Figures shown include hardware, software, installation, integration with billing only, training, & vendor deployment support.

Costs vary widely; figures shown are approximate, middle-of-range, for estimating purposes only.

Actual values will vary substantially with size of project, geography, customer density, functional requirements, meter inventory, corporate strategy, & many other factors.

Drive-by does not always cost less than fixed network. A power line system may cost less than a radio system.

O&M costs are not shown, vary widely, and appreciably affect annual net benefit.

Product status, risks, performance & other factors vary widely & often have cost & benefit consequences.

Assumptions

Saturation deployment.

Typical mix of single-, network-, & poly-phase meters.

50/50 meter retrofit/replacement.

Other Input Data

A wide variety of other data is required as inputs to the business case model. For example, see lines 8 and 20 in Figure 7, where the labor rate applicable to the labor saving appears. Other utility-specific data essential to the benefit calculation are shown in lines 21 through 24.

Other examples of utility-specific data in the business case include:

- Labor rates for all grades of affected labor
- Overhead and markup rates for all affected departments
- Hours and quantities drawn from activity analyses (number of off-cycle reads per month, customer outage minutes per year, number and cost of meter reader vehicle accidents per year, etc.)
- Details about the customers served (number of indoor meters, outdoor meters, pit-set meters, etc.)
- Financial metrics (weighted average cost of capital, revenue from residential customer, revenue from C&I customers, etc.)
- Costs of power under varying conditions
- Physical asset data (number and age of meters of each type, number of distribution transformers, etc.)
- ... and many other details.

All these data are needed to estimate the costs and benefits of AMI for the utility. Done well, the complete process, including solicitation and evaluation of vendor costs, takes 6 to 12 months.

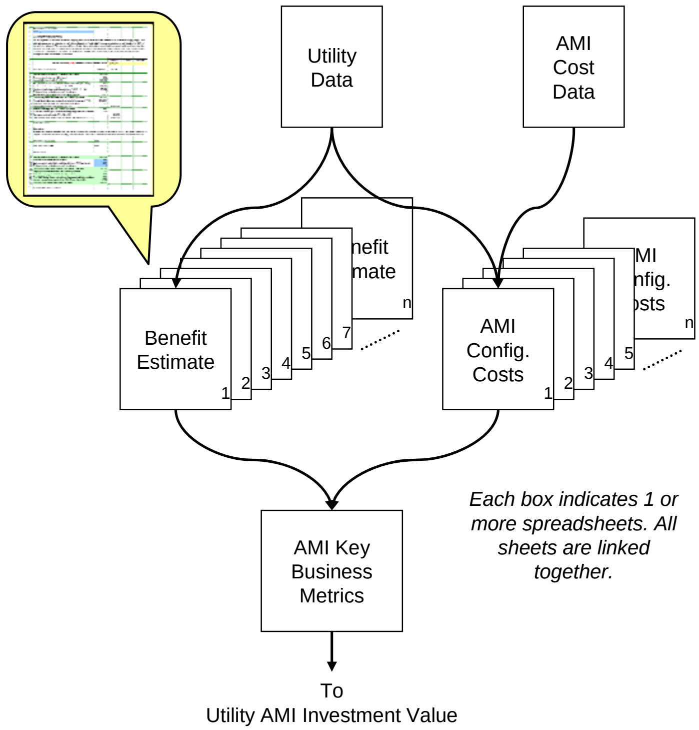
Assembling the Model

Model Structure

The AMI business case model is the central tool for analyzing the consequences of the AMI choice. The quality of the model has a direct bearing on the quality of the choice it supports. Considering the size and implications of the AMI investment, it is difficult to overstate the importance and value of a capable, high-quality business case model.

An example structure of an AMI business case model is shown in Figure 5. The various boxes shown refer to business case elements we have discussed above: utility data, benefit estimates, etc. For example, the Example Benefit Estimate shown in Figure 4 might be the third benefit estimate shown in the figure below. As explained earlier, the utility data (e.g. labor rates) feed into the benefit estimates, as shown below.

Figure 5: AMI Business Case Detail



The AMI cost data are usually provided by AMI suppliers, MDMS suppliers, integration contractors, and all the parties the utility will engage to accomplish the AMI deployment. If less precision is acceptable, a consultant with extensive recent experience can provide typical cost data.

We will need to assemble the costs of each AMI deployment alternative of interest. We can think of each alternative as an "AMI configuration". Configurations are not necessarily specific to individual vendors. For example, one AMI configuration may be a saturation deployment of fixed radio network from a single vendor. Another configuration may comprise that same radio network in the urban and suburban areas, combined with a power line system in the rural areas. Each box in Figure 5 labeled "AMI Config. Costs" is a spreadsheet that calculates the costs[10] for a specific AMI configuration the utility wishes to consider. The business model allows the utility to arrange configurations of interest, to experiment with them, and to test the sensitivity of the investment result to variations in the AMI deployment choices.

Multiple Operating Companies

The steps shown in Figure 5 produce values of key metrics for the AMI system. These include:

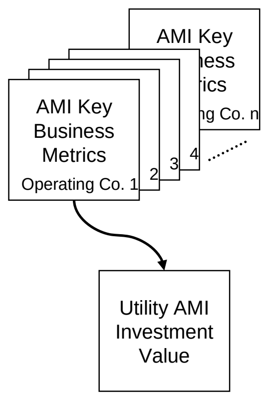
- Gross acquisition cost (including installation & commissioning)

[10] These costs are the amounts paid to the AMI supplier(s). Amounts not paid to the AMI supplier(s) are estimated and included in the benefit estimates, because they are most readily identified and estimated during the exploratory process of discovering benefit potential.

- Net acquisition cost (i.e. net of immediate benefits, such as avoided meter purchases, cash flow advance, etc.)
- Annual O&M cost
- Annual net benefit
- Simple payback (net acquisition cost divided by annual net benefit)

The next step, shown in Figure 6, calculates the investment measures the utility chooses to use for its evaluation. In Plexus experience, every utility will want to see the internal rate of return (IRR) and the net present value (NPV) of the AMI investment. Individual utilities will require additional value that may be utility-specific. Examples include earnings impact, present value of revenue requirement, and first year economic carrying charge.

Figure 6: AMI Business Case for Multiple Operating Companies



Because the calculations in the first step are simpler, the AMI team can use the model elements shown in Figure 5 to explore quantitatively a dozen or more AMI alternatives and develop substantial insight into the advantages, benefits, and challenges of each. When the AMI team has finished this effort, and chosen a “first short list” of candidates, the utility's financial team becomes closely involved in assembling the elements shown in Figure 6. The model of Figure 5 is used to derive the key metrics for each AMI configuration on the first short list for each operating company of the utility. These are combined as shown in Figure 6 to calculate the desired investment measures (IRR, NPV, etc.) that show the investment value. This calculation requires detailed assumptions about deployment speed, depreciation, and rate of benefit development for each AMI configuration.

The model spreads the costs and benefits over time to calculate the performance of the AMI system as an investment for the utility and its customers. It shows the costs incurred over the deployment interval, typically one to four years. And it shows the benefits emerging over a similar period as the system is deployed and utility processes are re-engineered to take best advantage of the new data resources.

IV. THE ENABLING TECHNOLOGIES: A BRIEF TUTORIAL

Metering & Data Acquisition

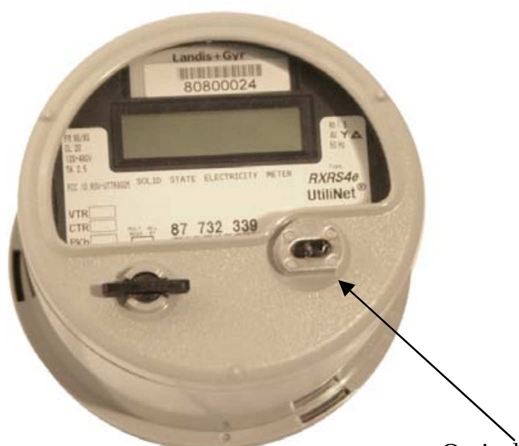
There are fundamentally four different approaches for gathering meter data for complex rates. Each uses commercially available meters from two or more meter manufacturers combined with some form of meter data communications.

Stand-Alone Complex Meter Read Locally

Meters with internal electronic clocks and ample memory are available that are readily capable of accumulating time-tagged data at 60, 30, 15 and 5 minute intervals for 40 days or longer. These meters are commonly used in commercial and industrial applications, but are also available in single phase, 200-amp versions for residential applications.

Data can be collected manually by attaching and infrared optical probe to the front of the meter, at the optical interface, visible on the lower right face of the meter shown in Figure 13. (This particular meter can also be read remotely, but that feature does not show on the outside.) These data are read into a portable reader carried by a meter reader. The meter data are uploaded to the billing system at the end of the shift.

Figure 7: Remotely Read Complex Meter



Optical Interface

Note: Figure courtesy of Cellnet.

This approach is preferred by some utilities who envision a very low level of participation in alternative rates by residential customers, and who may prefer to read other meters manually or with a “drive-by” meter reading approach in which, once a month, a vehicle passes within a few hundred feet of the meter and acquires total energy data from a meter equipped with an short distance radio communication capability.

What are the *pros* and *cons* of this approach? The *pros* include:

- Simplicity
- No fixed communication infrastructure
- Low overall cost-if there is only a small number of participants.

The *cons* include:

- A comparatively costly meter such as usually used for C&I customers
- Usually requires an optical probe reader to be carried by the meter reader
- Requires a special trip to install or remove
- Doesn't support “dynamic rate forms” since there is no communication with the meter other than a manual visit to the meter

Stand-Alone Meter Read Remotely Over “Public” Infrastructure

A simple meter or complex meter may be equipped with an internal communication device, or the meter may be connected to an external communication device, usually mounted in close proximity to the meter. The communications will typically be by using a telephone line (either a dedicated line or sharing the customer's line on a non-interference basis), a cellular phone, or two-way paging based technology. This obviates the need for any utility investment in communications infrastructure, but the cost of acquiring the data over a network owned by others is usually higher than in a utility-owned fixed network (assuming saturation deployment). Accordingly, this approach is most frequently used:

- With larger customers, whose high use/high revenue implication easily justifies the communications cost.
- Where customers are highly dispersed geographically, and dedicated fixed network is simply too costly.
- Where the small number of customers on the alternative rate doesn't justify the expense of utility-owned fixed network system.

What are the *pros* and *cons* of this approach? The *pros* include:

- Simplicity!
- Taking advantage of a fixed communication network that is owned and maintained by others.
- Ability to obtain data or reprogram the meter without having to go into the field.

The *cons* include:

- Problems associated with sharing a customer's phone line.
- Recurring costs to use some one else's wide area network.
- Costs for the communication module.
- Need to maintain a “head-end” data and network management computer.

Meter with Short Distance Communication Upgraded to Fixed Network

Many utilities have installed so-called "drive-by" AMR systems in the last 20 years. These are by far the most popular of the remote meter reading approaches, simply because they are the least costly to purchase. A roving vehicle passes within a few hundred feet of the meter once each month. The meter contains a transmitter that sends the total energy consumption value. This vehicle is typically capable of gathering up to 10,000 meter readings per shift. For comparison, manual meter readers typically collect between 100 and 1,000 readings per shift.

"Drive-by" systems gather data only when they are near the meter, and the information gathered is sufficient only to provide a total energy consumption reading with a few additional bits for simple items such as tamper detection and/or blink count. TOU rates for C&I meters can be read with drive-by because C&I meters can hold multiple drive-by radios. But multiple radios are not cost-effective in residential applications. Thus, drive-by systems generally do not support practical TOU or other alternative rate structures for the residential sector.

The leading supplier of these drive-by systems, Itron, has announced a "migration path" to convert an existing drive-by system to a fixed network by adding the radio infrastructure. This eliminates the roving vehicle and supports more frequent gathering of meter data for TOU and certain alternative rates. Addition of a fixed network infrastructure is not inexpensive. The company is now offering a higher powered meter communication device on new applications to improve the range and thus minimize the communication infrastructure. At this writing, there are no large deployments of the "migration path" approach to converting drive-by to fixed network.

Private Fixed Network AMI System

Utility-owned fixed network meter data acquisition systems that serve all or most utility customers provide a multitude of benefits beyond the mere ability to gather billing data. There are two prominent technology categories: radio frequency (RF) and power line communication (PLC). Within each category at least three well-established suppliers offer fixed network systems. Many more systems are emerging in the RF category, including various topologies, licensed and unlicensed, and high and low powered. A residential fixed radio network meter is shown in Figure 8. The meter shown in Figure 7 is a C&I meter for the same radio network; both can also be read locally through the optical port.

Figure 8: Private Fixed Network Residential Meter

Note: Figure courtesy of Cellnet

Most utility applications discover that the RF approaches have a cost edge in relatively dense suburban and urban environments, and that PLC approaches tend to be more economical in less dense or widely dispersed applications. Either can be made to work technically in both dense urban or sparse rural environments, and anything in between. It comes down to cost and benefits. Utilities are also considering mixed technology or "hybrid" systems, consisting of RF in urban and PLC in less dense areas. Recognizing this trend, leading suppliers are forming alliances that allow them to propose mixed technology systems, optimized for the environment, and with a single source of system responsibility. This relieves the utility of attempting to guide a mixed technology implementation or to form "shotgun weddings" of competing vendors.

Many utilities have justified fixed network systems based on the combination of the economic benefits derived. If a significant percentage of residential customers is likely to be on a time-based rate, a fixed network system will almost always be the most economical way to serve them. However, the pervasive benefits of fixed networks to utility operations are large enough that many leading utilities have justified such systems without any plan or desire to implement TOU rates!

Communication for Control

Communication Alternatives

The basic mechanism of demand response is that the utility informs the customers when electric market conditions change, and customers (or their automated loads) respond. The utility can inform customers by many means, including:

- Newspaper
- Audio broadcast radio
- Television
- Fax
- Telephone
- Email

The first three are true "broadcast" methods that reach large numbers of customers. But these must be initiated many hours in advance of the need. The next two can reach customers on fairly short notice, but may be ineffective because they require manual response by customers. Also, these particular methods are uneconomic for large numbers of customers. Email can reach many customers very quickly, but customers may not read the messages promptly. A near-real-time signal is needed if we are to implement a demand response program that can respond on short notice to electric market events. Alternatives for near-real-time communication include:

- The path used by an AMI system to communicate with meters
- Private VHF or UHF radio (owned by the utility, municipalities, etc.)
- Paging
- VHF broadcast radio subcarriers (that is, inaudible channels of broadcast FM radio stations)
- Digital cellular phone (audio or short-message channels)

The communication technologies of most AMI systems can be used not only to gather meter data, but also to issue near-real-time control signals. Three available power line systems can send signals to all, or any subset of, customer sites within minutes of the need. And several of the radio AMI systems can do the same. But it is not necessary to use the same communication for both metering and control, and in some cases it will be more economical to separate the two data paths.

Controllable Thermostats

Traditional control of air conditioning loads simply turns off the cooling device in the air conditioning equipment for, say, 15 minutes at a time. This has worked well and achieves valuable load reduction. But this method of load reduction has problems in fairness and free-ridership and, according to studies, is not as effective as newer methods.

Various studies11 have indicated that a fairer and more effective way to manage electric demand, where air conditioning (A/C) is popular, is to communicate with the A/C thermostat. The utility issues a signal informing customers' thermostats that a load reduction is in process. The thermostats respond with a pre-programmed change in the temperature set-point. Thermostats that can do this are available from several manufacturers. Figure 9 below shows one example. Some can be reprogrammed "over the air" to increase program flexibility.

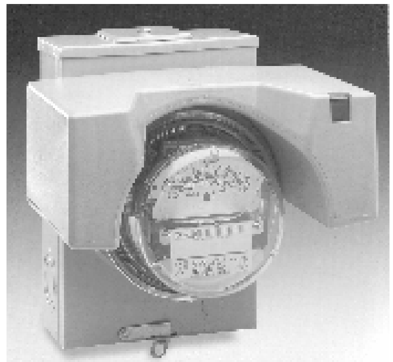
Figure 9: Communicating Thermostat

Note: Image courtesy of Comverge Inc.

Other Controllable Loads

Pool pumps, spas, water heaters, and electric thermal storage heaters constitute substantial loads that also can be controlled in response to utility signals and customer preferences. Available technology is amply capable of managing these loads using classical utility direct load control. But demand response is a new enough idea that few "off the shelf" products are available to enable customers to manage these loads in response to electric market events. One existing product, shown in Figure 10, is used by Gulf Power for its demand response program.

Figure 10: Demand Response at Gulf Power



Note: Image courtesy of Comverge, Inc.

The hood around the meter contains paging electronics, a telephone modem, a modest amount of computing, and means to communicate with the thermostat and load switches in the home to respond to an event signal from the utility. The thermostat constitutes the user interface through which the customer establishes response preferences.

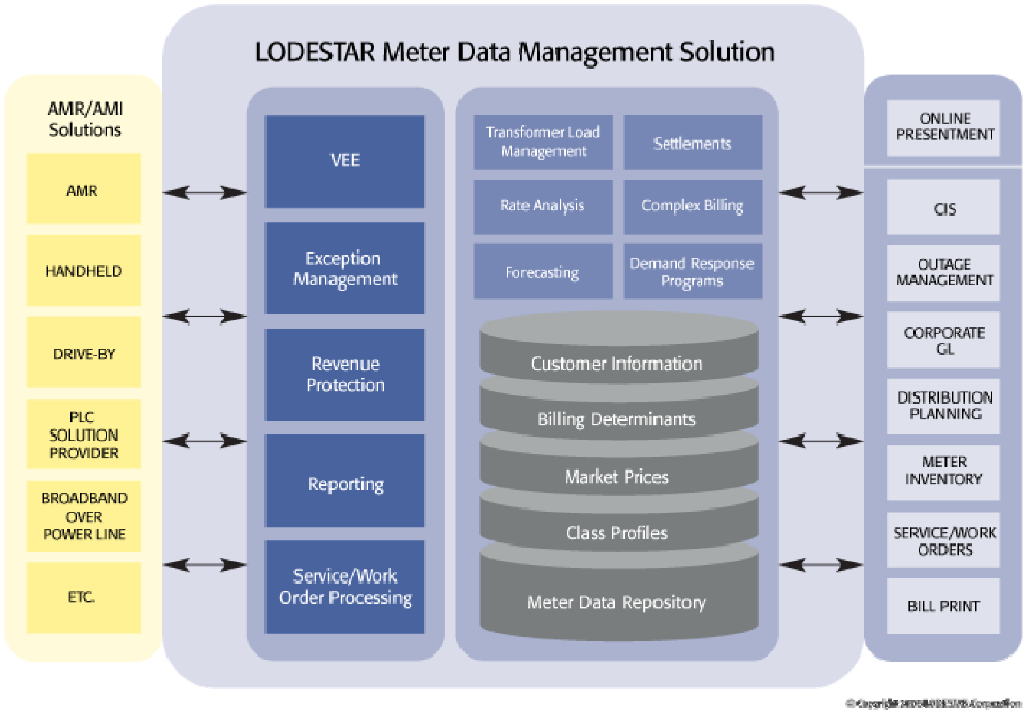
Getting the Benefits - Meter Data Management

Early AMR systems served principally to support billing. Once the meter data arrived at the utility, they followed the same path whether the readings were collected manually or remotely. In those days, it was enough to create an interface from the AMR system to the billing software, and call the project done.

AMR systems are expected (required!) to provide much more benefit now, and interfaces to many more utility systems are essential. Ten years ago, these interfaces were created by utility IT teams or outside contractors, and were unique to each installation. Best practices and the emergence of a work force skilled in such interfaces have catalyzed creation of a new software “space” called meter data management. A meter data management system (MDMS) is a suite of software, hosted on computing hardware, that transfers data and commands among the AMR system and all the utility's operating software systems. At least a half dozen well-established firms now offer MDMS suites.

This business area is so new that no consensus has emerged on the precise definition of an MDMS. Figure 11 illustrates one MDMS concept. It shows meter data entering the figure from the left side, via any of several paths, potentially including multiple AMI systems. The MDMS in the center processes and stores the data, and serves them to the utility applications on the right side of the figure. Utility planners must now assume that some kind of MDMS will be a prominent project requirement in any large AMI deployment.

Figure 11: MDMS Concept



Note: Figure courtesy of Lodestar.

V. ECONOMIC & TECHNICAL IMPLICATIONS OF TECHNOLOGY CHOICE

Rate Implications

Any quest for the best strategy in implementing innovative rates with residential customers must start with what is already known and what may be safely assumed. What is the best choice? It depends. We mentioned in the introduction to this Guide that four guiding factors must be addressed:

- What existing metering infrastructure already exists, its age, and its capabilities?
- What peak or time-sensitive rates are already offered? Will this change?
- What alternative rates are candidates? What are their data requirements?
- What level of customer participation in alternative rates is expected 1%? 8%? 40%? What level is desired?

Many utilities already have seasonal rates. These are time-differentiated rates. No special metering is required. Many utilities already have various peak-sensitive, time-based or demand rates for commercial and industrial customers. But the EPAct requires the consideration of all customers, so the residential sector is where the challenges lie.

Accordingly, the following discussion addresses the residential sector which, importantly, is characterized by the following features relative to the C&I sector:

- Much larger number of customers
- Lower level of energy use, and therefore lower revenue
- Less sophisticated customer
- Much greater cost sensitivity for metering apparatus (due to lower revenue)

We observed elsewhere in this Guide that many utilities dived into TOU metering after PURPA 1978, only to find

Choosing Technology

Choosing an AMR/AMI system is complicated. Accordingly, most utilities involve an expert that specializes in the field. Since these systems are purchased only once each 15 to 20 years, few utilities have the on-staff expertise. The size and life of the investment make it essential to get it right. Everyone naturally looks—as well they should—for ways to simplify the selection process to arrive at a “right” result.

Conventional wisdom derived from years of experience holds that radio systems are generally more economical and effective in denser population areas, and power line systems are the right choice in areas with sparser population. This is generally correct, and we have included that notion in this Guide. It follows logically that a utility can examine the geographic distribution of its meters and narrow the technology choices early in the process. Doesn’t it?

Emphatically, no. Here’s why …

Technology continues to evolve, and that evolution becomes most evident in competitive AMI proposals. AMR/AMI developers always have new features and capabilities in development, not revealed to the public. When developers compete for a significant new contract, they pull out all the stops and offer their best capabilities, often including things that have not yet been shown to the public.

The technology improvements of the last decade have substantially narrowed the capability and price differences between radio and power line systems. This evolution surely will continue. An AMI planner that presumes to know these differences in advance risks making a choice that will turn out to be suboptimal, perhaps substantially so.

The best result will be achieved when the technology choice is guided by the ability of the proposed AMR system to meet the functional requirements *and provide an attractive investment return*, not by “conventional wisdom” that may or may not apply.

that after five or ten years the level of residential participation in voluntary TOU had fallen steeply. Clearly, the customer will decide whether he prefers the utility's “flat” rate or TOU rate, and whether the savings in TOU are worth any inconvenience they may require.

This brings us to the critical importance of the rate design to the sustainable level of participation in a voluntary residential TOU rate. Clearly, dramatically higher on-peak rates are more challenging than rates with smaller on-peak/off-peak differentials. Similarly, a TOU rate with long on-peak period is much more difficult to live with than a short “spiky” peak period. A weather sensitive peak period in southern states, hot with high humidity, may begin in mid-morning and extend late into the evening.

A detailed discussion of rate design considerations is outside the scope of this Guide. It is sufficient to state here that the initial level of participation in TOU rates by residential customers, and their retention over five or more years is very much a function of the TOU rate design, the consumer's ability to control consumption during high cost periods, and the other alternatives that are available.

The classical single-register induction Watthour meter for residential service costs between $20 and $30 new. The modern solid state electronic version of this meter will be in the same price range. Any technology chosen to implement TOU or dynamic rates will increase the cost at that location, whether it is simply a more competent meter with an optical port for manual data retrieval, or whether that meter is part of a full-function two-way fixed network.

Historically, many utilities assessed a special “metering charge” for the more costly and complex meters. That meant that a TOU customer might alter his consumption and save, perhaps $8 a month. But if there is a special metering charge of $6, the net saving to the consumer is only $2. That customer may rapidly lose interest! This problem with the impact of the metering charge was one of the factors that “sank” the large Puget Power TOU installation. Utilities must consider this matter carefully.

Customer Participation

PURPA instructs us to consider equipping all customers to respond to electric market conditions and events. But how many customers will choose to participate in such response? The answer to this question can have a determining impact on the optimal technology choice.

As an example, suppose that our metering requirement is as follows:

- Record monthly energy consumption at all sites.
- Record TOU consumption at fewer than 10% of customer sites. These are customers who elect the TOU rate, and they are physically dispersed throughout the territory.
- TOU rates have been offered, and customer response has shown a strong preference for simple “flat” rates. We have no reason to expect any change in this preference in less than a decade.

In this situation, the utility and the customers may be most economically served by a saturation deployment of drive-by AMR, augmented by a “drop-in” technology for TOU reading that can be installed as needed at individual sites.

In contrast, imagine a very different metering requirement, as follows:

- 60% to 80% of customers will elect a TOU rate or other utility program such as demand response that relies on the AMI.
- We require the ability to offer any and every customer a time-dependent rate.
- We must be able to establish or change this service at any time on short notice.

In this case, a saturation deployment of a highly functional, fixed network AMI system is likely to provide both the best service the best financial return for the utility and its customers.

The fixed network will cost more than the drive-by system, but will meet requirements that the less expensive system cannot meet. Further, the versatility of the fixed network obviates many risks of deploying more limited systems related to unknown future needs for meter data.

This illustrates why it is so important to define the functional requirements before considering solution options. If we do not need a function (such as TOU support, or hourly meter data recovery), identifying it as “required” can add many millions of dollars to the system cost without producing a corresponding benefit. At the same time it is worth noting that, because a fixed network provides many more benefits in traditional utility operations than a less capable system, for some utilities the fixed network will be as good an investment as a drive-by system even if no TOU or other “advanced” functions are required now. A competent business case analysis will show when this is true, built on a detailed assessment of AMI benefits and costs.

Value of In-Service Meters

One crucial aspect of the economic justification of AMI systems is easily overlooked until late in the game. It can influence a utility to reject an otherwise positive business case. It is the accounting treatment of the value of in-service meters.

Some or all of the existing meters in the field may be replaced with new meters. But meters removed from service are likely still “on the books,” and their undepreciated value becomes a write-down, that is, a loss. From a book or net income perspective it appears as an AMI cost which can have a significant impact on reported income. This write-down may impact regulated income as well unless there is an appropriate regulatory treatment of this issue.

The book value of in-service meters is often substantial because meters have a long life in service and on the financial books. Meters are normally entered into the books at their installed cost, typically something between $50 and $65 per meter for a simple residential kWh meter. This usually includes the purchase cost of the meter, the utility's cost of receiving, testing (if any), handling, and installation at the customer premise. A meter that is capitalized at $60 and depreciated in a straight line over 30 years will have a book value of $20 after 20 years of service. If this meter is replaced (rather than retrofitted) during an AMI deployment, the utility incurs a write-down or a “loss” of $20. This can be a very significant addition to the AMI system's cost-per-meter, which may range from $100 to $200.

This effect on book and regulatory income can be a major driver of the AMI approach. Utilities that must incur this “loss” in the year the meters are removed from service may look to retrofit AMI communication devices to existing meters and redeploy them.

In the bigger picture, many utilities conclude that new technology has rendered induction meters obsolete, and-if the write down of the book value can be dealt with-it makes little sense to retrofit those meters with communications and return them to the field.

The issue of depreciation of new meters takes on a new meaning in the context of AMI systems. Many utilities traditionally depreciate “communications equipment” on a much shorter schedule (perhaps 7 years), than meters (perhaps 30 years.). But if we install communications in the meter, which schedule should pertain? The communication and metrology functions are closely integrated in most new solid state meters. It is unlikely that, after 10 years, the meter can be retrieved from the field, the communications section removed and replaced, and the meter sent back to the field. This may be technically possible, but it is economically unattractive. A need to harmonize the actual and depreciable lives of the meter and its communications is emerging as electronics now replaces the moving parts and gears of the induction meters. Most current practice projects a 15 to 20 year life of the solid state meter with its communications.

Customer Gateways

If a utility can communicate with a meter, if it can send commands and programming instructions to the meter, and if that utility can receive meter data and information on outages, tamper, load profiles, voltage and other information from the meter, then what else can be done with this capability? What about sending weather forecasts, stock quotes or baseball schedules, or receiving intrusion or fire alarms? It is an intriguing thought. It is an idea that has attracted many competent technology firms-and put them out of business.

Technology is not the problem. The difficulties arise from:

- The higher first cost of the equipment
- The spotty level of customer acceptance
- Their willingness to pay for additional services
- Problems with using the meter as a portal through which to deliver these services
- Cross-subsidy issues

This is not to say that there may not be some future role for utility metering in gateway enabled services. But meter data are of relatively low value. It is more likely that meter data will ride on a communications platform designed for other, higher-value services than the other way around. The market has spoken on this issue many times in the past 35 years, leaving many well intentioned-and now defunct-companies in its wake.

VI. BEST PRACTICES IN PURCHASING, INSTALLATION & INTEGRATION

Throughout this Guide we have described an effective process for evaluating AMI systems. The basic approach is to define the long-range vision and consequent business needs first, then identify and quantify the potential business benefits. This reveals the technical requirements. Let the vendors show you how they can meet those requirements, and choose the AMI system that delivers the best business value, measured by the business case.

This section of the Guide describes additional points and tips for achieving an optimal result.

Get the Sequence Right!

The Vision Comes First!

The first step is to review the current situation. What rate structures pertain to each customer class? Most utilities already have complex rates for larger customers that have time or peak demand components. Most utilities have rates that are seasonally differentiated. Many utilities have substantial experience with time-of-use rates in the residential sector. How is all of this expected to change in the future, measured at five-year intervals out to 20 years or more? Yes, an element of crystal ball gazing is required because we are discussing a large investment in a system that must serve us for at least 15 years, and has important consequences past 20 and 25 years.

Requirements Next

Most utilities are tempted to begin assessing metering and AMR/AMI options by first seeing what is available for technology. That is not difficult, because every utility is constantly besieged by vendors asking to come in to present a “dog and pony show.” This does not seem unreasonable at first glance, and it is useful to become familiar with the capabilities and limitations of available systems. But it is a mistake to begin a technology selection this way. Technology and vendor assessment must come later. Too often, one or more members of the AMI team fall in love with a technology or a vendor without a full understanding of what is to be accomplished. That dramatically confuses the process of selecting the most suitable technology and approach. The first step after the vision is always to carefully and objectively define the requirements for a system that supports the vision.

Requirements Evolve

Since each utility's requirements, current costs, operating practices, and prior experience with alternative rates are different, each utility must create its own vision for the future. It must make its own assessment of what number of customers is likely to be on alternative rates in the future. We suggest that there be a series of most likely scenarios, at 5 year intervals, indicating what kinds of meter data must be obtained from what number of customers, by customer class. For example, if there is a likely forthcoming requirement to offer and implement a “dynamic” rate form in which either the price per kWh will change on short notice, or a “super-peak” billing component will occur, this must be identified.

Technology & Vendor Selection

Once the utility has developed its business case, that business case establishes which attributes of an AMI system will produce the greatest and, therefore, the most essential value. These become the required elements of the future system. The non-essential but desirable value contributors come next. And finally the low value or unquantifiable benefits are the optional elements. As noted in preceding paragraphs, this gives you the essence of the system specification and the core of the RFP. Once the responses to the RFP come in from the vendors it is important to have an unbiased, documented and supportable evaluation process.

A scoring system is established that rates the compliance of the proposals with the specification contained in the RFP. Any AMI system, regardless of technology, that cannot accomplish a required function must be eliminated as technically unresponsive. The lesson here is: If you state that a function is required, you had better really mean required! The process of scoring proposals is confounded if the so-called requirements become fluid during the evaluation process.

Next comes the matter of establishing the ranking of proposals by cost. This is no small task, and it requires considerable familiarity with the various systems and vendor approaches. Why? Because the proposed costs are never directly comparable. Each system requires certain utility-furnished equipment, either in the substation or out in the distribution system. There is also the labor at the meter level, other labor in the wide area infrastructure, and at the head-end. There are wide variances in proposed training, on-site field installation support, system documentation, extended warranty provisions, on-site spares, and many other factors. So it is absolutely necessary to “normalize” the cost proposals to get true apples-to-apples cost comparisons.

Two more influences play into the overall proposal scoring and selection process. These are vendor assessment and risk assessment. The most extensive performance claims and lowest cost mean very little if the supplier is inexperienced in systems of this size. The risk is high. Yes, there are techniques for mitigating risk that must be employed in all cases, with any vendor.

Finally we emerge with a process that thoughtfully established:

- Compliance with required functionality
- Assessment of the value of desired functionality
- Clear and comparable costs associated with each qualified proposal
- Metrics qualifying each vendor's performance capabilities
- Measures of risk, and how that risk may be eliminated, reduced or mitigated.

But we still are not done. At this point a “short list” of companies is composed. It lists vendors whose systems can meet all requirements and whose costs are within reasonable range of being justified by the business case. These vendors are normally invited in for discussions, questions and clarifications. Finally the utility opens the window for “best and final” adjustments by the short-listed vendors, and negotiation can commence with one to three of the qualified finalists.

Potholes & Mines to Watch Out For

Do-It-Yourself Is Costly

The most efficient progression through the process of selecting and contracting for an advanced metering/meter data communications system will be assisted by an experienced consulting firm specialized in these applications. These firms tend to be highly focused “boutique” firms. Unlike poles, line trucks or transformers, a utility will procure an AMR/AMI system only once every 15 to 20 years. Thus, the required expertise is seldom available to a utility in-house. The proper development of a business case, RFP, technology selection, vendor selection and contract development and negotiation is complex, and has nuances not found in other utility procurements. Why? Because these applications require smoothly functioning systems composed of a very, very large number of relatively low cost devices, all performing unattended in harsh environments for many years. This system is the cash register for the utility. It must not fail.

It is very rare that a utility attempts to procure a large AMR/AMI system without outside consulting assistance. That consulting assistance must be highly experienced, technically expert, practiced in sophisticated justification mechanics, credible to top management, ethically untainted, completely objective, and vendor-neutral.

The Cost of Overstating the Requirement

Know your requirements. It is easy to say, “We'd like hourly data from all customers.” But it may be far more valuable to say, “We'd like each meter point to be capable of returning hourly data when we need and request it.” Why process 720 data items from each customer every month when most customers will simply receive a monthly total energy bill and one data item will suffice? The cost of recovering hourly data from all customers may far outweigh the value of the result. A sound business decision requires the utility to define the vision first, then identify the data required to support the vision (hourly data, monthly data, etc.), then define the technical requirements of the AMR/AMI system to recover those data.

By establishing a set of requirements that reflects what you really need, you will preserve the maximum number of options, reduce the complexity and the cost of the approach you select, and accelerate the successful implementation of the system.

IT Integration Challenges

As mentioned earlier in Getting the Benefits - Meter Data Management (page 30), the MDMS is the functional element that accomplishes IT integration. It receives data from the AMI system, processes it and stores it, and serves it to the various utility functions that need it, such as outage management, distribution engineering, billing, etc. MDMS systems with varying capabilities are available from several providers. Each is aggressively expanding the versatility of its offering as the market for MDMS expands.

MDMS suppliers provide the service of integrating the MDMS with the AMI system and utility legacy systems. Utilities with a large and skilled IT staff may elect to do some or all of this integration themselves. In more complex situations, the utility can hire one of the contract system integration firms that specialize in AMI systems.

In recent years, utilities with well-staffed IT departments could readily do their own AMI IT integration. The ascendant strength of the commercial MDMS and integration service offerings is prompting a pronounced shift in this practice. Even a large and capable IT department may now be well-served to engage an outside firm that specializes in AMI integration and MDMS.

Contracting Exposures & Countermeasures

AMI system acquisition presents contracting challenges that are not familiar to most utilities. Specifically: The utility is acquiring a very, very large number of low cost electronic devices that must be delivered and installed in a hostile environment in a short period under demanding circumstances. And this large number of devices must perform flawlessly as part of a large communication system, unattended in the field for 15 to 20 years. This is a system. That word, system, has a special connotation. A product may test perfectly in the factory, but then may not communicate successfully in the field. Why? Is it the product? Is it the terrain? Is it the rest of the system? Is a limited 90 day or one year warranty on workmanship and materials meaningful in this case? No. We need to be assured of performance at the product level and at the system level.

There are many tales of electronic products where alarming quantities suddenly begin failing at perhaps 4 years or 6 years into the life of the installed system, past the end of the usual warranty. These premature failures may be due to a design flaw or to a batch of defective electronic components exhibiting “infant mortality” problems. If this happens, we are faced with many known failures and high odds of many more failures to come. Until we fix this problem, we must find a way to read these meters. Who pays for that? Who pays for new units to replace the failed or failing products? Who pays for the labor to remove the failed products and install new products? These issues, not part of the typical utility experience, must be anticipated in a contract.

Other contracting considerations must include provisions for formal technology escrow and access to manufacturing so that if a supplier goes out of business, or otherwise cannot supply support and additional products for system maintenance and expansion, the utility can go elsewhere for compatible equipment.

Turn-Key Contracts

Turn key contracts are popular with utilities who wish to place all responsibilities-the system, installation, integration, commissioning, acceptance testing, and initial operation-on a single contractor. Several major AMI vendors actively solicit turn-key projects. Others absolutely are unwilling to accept such contracts. There are significant cost exposures and risks for the turn-key system vendor that must be reflected in higher costs passed on to the utility.

Outsourcing Models

Utilities that wish to deploy advanced metering systems have many options. One approach is to procure, install, own, operate and maintain an end-to-end AMI system. At the opposite end of the spectrum, a utility can contract with a vendor or third party who will install, own, operate and maintain the AMI system, and will sell the meter readings to the utility for an agreed price.

And there are examples of everything in between. For example, the utility may own the meter but the vendor owns the rest of the system. Or that vendor arranges for the wide area communication infrastructure and the utility owns the rest, paying a monthly charge for use of the infrastructure.

Mixed Technology Systems

We have noted earlier in this Guide that any technology can be made to work in any area at some cost, most of them are better suited to some requirements that others. For example, hilly terrain, dense foliage, and widely spaced customers challenge the economics some of the radio systems. Conversely, power line communication system may have technical and economic difficulties in urban applications. But there are no hard and fast rules, and other technical issues may override simple cost considerations.

For utilities with widely varying environments, customer densities, terrain issues, and needed capabilities, it may be unlikely that “one size fits all.” This leads to mixed-technology systems where, for example, large commercial and industrial meters may be read over dedicated phone lines or digital cellular, urban gas and electric residential using radio, and rural electric using power line communication. Vendors have recognized this need, and several prominent vendors will now take full responsibility for providing the products of their erstwhile competitors in an integrated system.

Installation Services Contracting

Replacing a very large number of meters, sometimes at the rate of 100,000 meters per month or more, is a major logistical challenge. Managing the incoming flow of new AMI-equipped meters and dealing with the removed meters, and the associated record keeping is crucial. At the same time, some of the meter sockets and service wiring will be found to be unsafe or unusable, and must be upgraded. And the installers must be motivated to look for signs of energy theft, that is, tampering with the meter or illegal taps or wiring around the meter socket. The customer may need to be notified of the planned installation, approval and access obtained.

Some utilities train their own personnel and those meter readers who will be displaced to do the AMI meter installation. Union bargaining unit issues often are prominent in installation planning. Some utilities prefer to subcontract the entire meter installation process to firms that specialize in this work, and do it very efficiently and economically. And some utilities use their own personnel for some of the work and contractors for the rest. Firms like Sargent Electric, Honeywell, MDI, Terasen, Tru-Check, VSI Meter Services, Bermex and others are highly experienced in AMI deployments.

VII. LESSONS LEARNED FROM PREVAILING PRACTICE

AMI systems have been commercially available for thirty years. By 1985, with the advent of the microprocessor and other advances in electronics, prices began falling, a trend that continues today. During the last twenty years, with millions of communicating meters in the field, certain lessons come through, time and time again:

- Utilities that install advanced fixed-network metering systems always discover new applications and always find additional sources of value, beyond those they originally expected.
- AMI systems are major procurements having long term strategic ramifications. Smart utilities assign a top management “sponsor” to shepherd the process and to illuminate the importance of the project to all personnel.
- Utilities considering AMI must form a task force to participate in the assessment, selection, and deployment processes. That task force must include senior representation from the many departments of a utility that will be impacted to obtain their insight and to earn their “buy-in.” Utilities that fail to build an internal constituency will have problems later.
- Justification of AMI depends on developing a business case that identifies benefits wherever they may be found. Most of the benefits appear as operational cost savings, department by department. To identify and include each benefit in the business case, the affected department must understand and “sign up” for that benefit. This benefit may come from reduced expenditures or reduced “head count.” It is human nature for department heads to resist reductions in their budgets or staff. So producing a competent business case is part art, part science and part economics. This process cannot be rushed. Plexus has found that it typically takes 2-5 months to do it well.

Required accounting treatment can be a significant driver of AMI strategy and business case results. It must be resolved very early in the process. The approach that must be used to account for the book value of meters removed from service varies from utility to utility, and from jurisdiction to jurisdiction. Examine this matter early in the process of developing the business case and strategy.

Long after the system has been installed, those responsible for the system must be attentive to software upgrades, new uses, and ensuring that the predicted benefits are indeed being obtained. The original business case is both the “menu” and the recipe of these benefits. Periodically benchmarking the AMI system performance against the business case illuminates successes and opportunities for more benefit. For this reason, the business case and the methods that support it must be living instruments, used and understood by utility personnel who are new to the process. An unwieldy or opaque business case has little residual value.

VIII. DECISION SUPPORT TOOLS

The complexity of the AMI decision and process can be daunting. Many a utility has struggled with it and concluded that the business case cannot be made positive only because the utility had insufficient experience in AMI planning to develop a positive business case and a clear plan. Many helpful resources are available. Simplifying assumptions help. Rules of thumb help. Two-step (or three-step or four-step) processes help. The following paragraphs describe a few decision support tools used by experienced consultants to the industry to assist utility clients

AMI Benefit Tree

The AMI benefit tree can take many forms. The one shown in Figure 1 groups AMI benefits in traditional utility operations into financial categories: avoided losses, reduced expenses, new revenue, etc. We could augment this by adding all the benefits of load management and demand response, some of which will appear under Intangible Benefits. A different partitioning altogether would show benefits by utility department: meter reading, metering, customer service, etc.

It is helpful to start the benefit estimating process with a kickoff meeting that serves as both a tutorial and a workshop. The tutorial content brings participants “up to speed” on the available AMI alternatives, and the workshop aspect has participants develop an initial sense of where AMI may produce value within each one's spheres of activity. The AMI Benefit Tree is a useful tool during this process to brainstorm and discuss the likely sources of benefit.

A typical AMI business case will show that six or eight benefit sources-that is, six or eight of the items listed in Figure 1-provide up to 75% of the total AMI benefit from traditional utility operations. The remaining 25% will come from 15 to 25 other sources in varying degrees. It may seem simpler to focus on the top six or eight, and surely it would. But this isn't enough. The business case will be very weak if that last 25% of benefit is not included. This fraction is so large that we cannot say to senior management, “We didn't look at the smaller benefits. They're usually about 25% of the total. So we've assumed that and increased our benefit prediction by that amount.” Management will rightly want to see more convincing assurance that this large investment will prove worthwhile.

So we must examine a large number of benefits. The AMI Benefit Tree allows the AMI team to see the whole picture at the outset, and measure progress as the work proceeds.

The 3 Phases of AMI Procurement

It is helpful to think of the AMI planning and acquisition process in three phases:

- Planning
- Procurement
- Deployment

Each involves qualitatively different activities. Success in each phase is a pre-requisite for the following phase. In California, where regulators and utilities are collaborating to plan AMI, a sub-phase for pilot testing has been included in the Procurement phase.

Pilot testing used to be common. But it is costly and incurs delay, and the maturity of available AMI systems obviates the need for pilot testing unless the utility is pressing the state of the art.

Planning

The Players: AMI technical team, financial staff, senior management sponsor

The Activities:

- Establish the business vision and consequent technical requirements.
- Evaluate AMI alternatives to assess feasibility of achieving the vision.
- Assemble a business case (estimate benefits and costs, as described earlier) to test the AMI investment performance

In some cases, the overall outlook for AMI is so positive the utility will prepare and issue a request for proposals (RFP) during the Planning phase to solidify the AMI costs in the business case with vendor commitments, rather than estimates. More usually, the utility will issue a less formal request for information (RFI). This establishes the viability of the business case before incurring the cost of a full RFP.

Procurement

The Players: Legal and procurement staff, supported by AMI technical team and consultants

The Activities:

- Acceptance Test definition
- RFP preparation and issue
- Proposal evaluation
- Vendor negotiation and selection
- Deployment planning (including Acceptance Test planning)
- Contract negotiation

The greatest value for the utility and customers will be gained if the utility invites AMI providers to meet its functional needs without limiting the ways those needs can be met. Preparing an RFP requires carefully specifying the utility's requirements without specifying the means of achieving them. The specifications included with the RFP become the guiding documents for the contract when the AMI vendor(s) is selected.

Quantitative proposal scoring tools will be developed in parallel with the RFP to assure that the vendors are evaluated point-for-point on their abilities to meet the requirements. The proposal evaluation is rigorous, intense, and a vigorous mix of quantitative and subjective evaluations. Effective evaluation tools will help the AMI team reach a consensus, rather than “voting” to resolve differences of perspective. Again, this builds “buy-in” among the participants that is extremely helpful when the utility later must manage business process transitions to garner the full benefits of AMI.

Negotiating the procurement contract is challenging. The supplier(s) will have done this many times, but the utility typically has little current experience with AMI contracts. A poorly prepared utility may over look an important issue or be out-maneuvered by supplier(s) unless the utility can draw upon the expert experience of others who have been through recent and detailed involvement in the AMI contracting process. Acceptance testing and warranty issues are particularly important when new technologies are to be deployed in large volumes.

Deployment planning is critical to success and must be part of the negotiation to craft an effective plan at optimal cost.

Deployment

The Players: Selected AMI technical team leaders (now managing the deployment), senior management sponsor

The Activities:

- Managing and auditing field activity (installation of meters and communication infrastructure)
- Integrating the AMI system with the utility's existing IT systems
- Managing and auditing the high flow of customer account data (read out, read in, meter numbers, service upgrades, etc.)
- Managing the high flow of hardware (mostly meters)
- Tracking contractual compliance
- Tracking and documenting system performance as installation tests proceed; conducting Acceptance Testing

AMI deployment typically is a high-volume activity that may involve thousands, or even tens of thousands of meter installations per week. Moving so much hardware at such a high rate, and changing so many customer accounts, is hard to do without errors. Errors are very costly to detect and correct later, and can balloon into disastrous public relations. So planning and executing the deployment receive top management priority.

After a few thousand meters are installed, the first stage of the Acceptance Test will expose any flaws in the system operation and the IT integration. If the flaws are more than trivial, this may suspend installation while the vendor remedies the problem. Then the day-to-day activity of installing equipment, gathering data, auditing installations, finding and solving problems will continue at high intensity for many months until the final Acceptance Test confirms the completed system is fully operational.

Adjunct Applications

AMI centrally alters metering and meter reading, and also affects the utility's future directions in related areas. Examples include:

- Load control, load management, demand response
- Outage management
- Net metering
- Field force automation
- Remote service switching
- Distribution system planning
- Distribution automation
- Resource planning
- Prepayment service
- Customer-site automation

Informed utilities think very carefully about their long-range needs in these areas before launching an AMI procurement, and often will include requirements for all these applications in the AMI procurement process.

From a technical standpoint, each of the above applications has historically been a stand-alone function, unrelated to the utility's mainstream metering. For example, early direct load control systems integrated with other utility systems only at the head end. Similarly, distribution management systems like capacitor controller were stand-alone and linked to other systems only at the utility console. The versatility of modern AMI systems has made it possible to economically integrate metering data into these applications, sometimes sharing the communication network and head end functions. The financial and functional advantages of this integration can be very substantial, but only if we think about them in advance and include these applications in our initial vision, strategy, and requirements processes.

IX. CONCLUSIONS & RECOMMENDATIONS

PURPA Section 111(d), as amended by The Energy Policy Act of 2005, contains language that requires state utility commissions to consider whether it is appropriate for utilities to offer customers time-dependent rates, and to provide and meter those rates for customers that request them. Many utilities already offer and meter voluntary time-of-use rates that fulfill this requirement.

Separately, PURPA also requires state regulatory commissions and unregulated utilities to consider whether it is appropriate to offer smart metering and, if it is, to set a smart metering standard for utilities. Appropriateness is established by the balance of costs and benefits, which fall into two categories: the metering, and the programs (for which the metering is pre-requisite) that enable customers to consume less energy during peak periods. The assessment of benefits may require looking into those that accrue only to the customer, in addition to those that accrue to utility operations.

This Guide describes time-tested and proven approaches to evaluating the costs and benefits of advanced metering systems, which produce many benefits throughout utility operations, even if no demand reduction programs are pursued.

In many cases, advanced metering systems will prove to be a good investment purely for the benefits they provide to utility operations, without respect to the requirement of supporting alternative rate designs or demand response objectives. For example, automating the formerly manual process of collecting meter data produces a significant operating benefit. Accordingly, many utilities have proceeded with an advanced metering system without the additional imperatives of advanced rate structures. They now have advanced metering infrastructure (AMI) in place that can support a wide variety of demand response programs. In addition, it also is possible that demand response alone will produce enough benefit to amply justify AMI.

This Guide discusses best practices in making technology choices. Interestingly, that process must not start with consideration of specific technologies. Instead it is imperative that requirements be established and valued before any consideration is given to specific technologies. This process begins with an examination of the many operational benefits of AMI systems, and which of these actually apply. That becomes the grist for the all-important business case, then the RFP, the vendor solicitations, evaluation, assessments, contracting, acceptance testing and full-scale deployment

This Guide describes the methods, insights, tools and perspectives needed to get it right.

GLOSSARY & DEFINITIONS

A few especially important words or expressions used throughout this Guide deserve some special attention since they are fundamental to this material and to discussions within the industry. We encourage readers to take a few minutes to refresh your acquaintance with these terms.

Automatic Meter Reading (AMR)

This term broadly encompasses any form of automation of the meter reading process, including drive-by and hand-held meter reading systems. The term Advanced Metering Infrastructure (AMI) applies only to fixed network systems.

Complex rates

Consistent with the EPAct, this Guide interprets complex rates to include any residential or C&I electric rate structure with billing elements that go beyond a simple monthly billing for total energy consumption. For example, any form of time-of-use rate, demand rate, dynamic or peak sensitive rates may be considered to be a complex rate.

Fixed Network, Advanced Metering Infrastructure (AMI)

Historically, meters were read by a human that visually read the meter dials and wrote the digits on a paper pad for later manual data entry. Later, meter readers were equipped with hand-held terminals into which the observed data was entered on a keypad. Data was then efficiently uploaded electronically after each work shift. Higher-end meters, as used for commercial and industrial customers, were typically read using an optical probe that interrogated the meter and recorded its data. In each of these cases, a human had to gain physical access to them meter.

A form of remote meter reading was developed in the 1980s that uses low power, unlicensed radio transmitters (communication modules), embedded in the meter. These modules periodically transmit a message that corresponds to total energy accumulation. The message can be heard by a receiver a few hundred feet away, either a hand-held receiver or one mounted in a vehicle driving through the neighborhood. These systems are now sometimes referred to as “walk-by” or “drive-by” systems, or as off-site meter reading (OMR), but in their early years were referred to as automatic meter reading systems (AMR). This created confusion, because they were automatic only to a point. There still had to be a person in the field, close to the meter, to acquire the reading. These OMR systems have been very popular with gas, water and electric utilities because they dramatically reduce labor cost, and improve accuracy and timeliness of the meter reading. But they do not support complex rates, read-on-demand, or many other attributes of a fixed network system.

Fixed network systems dramatically reduce or eliminate the need to have personnel in the field for meter reading. A “fixed network” is any communication network that is in place all the time (is not moving) and reaches the meters. The meters are equipped with communication capabilities, usually by radio or power line. Telephone, digital cellular and satellite are other less widely-used options. The meters communicate through the fixed network with data collector/data concentrators strategically located to ensure adequate coverage. The collector/concentrators may be located throughout the distribution system in the case of radio systems, or at the substations in the case of power line communication. These devices, in turn, communicate to the system "head end" computers that manage the network and the communication processes. The "head end" will interface directly to the billing system, customer information system, outage management system, etc., or through a "meter data management" (MDM) system.

Most fixed network systems can read any meter any time, and support a wide variety of complex rates. These systems have proven to have value that extends far beyond simple meter data acquisition. This value proposition is addressed in the business case section of this Guide.

The capabilities of a fixed network system are far greater than those of a drive-by system, but a drive-by system is simpler and has a lower initial acquisition cost. To avoid the confusion that arises when drive-by systems are referred to as automatic meter reading (AMR), a new term was coined to describe fixed network systems. That term, Advanced Metering Infrastructure (AMI), is rapidly gaining acceptance. It applies only to fixed network systems capable of supporting complex rates. We have used the term in this context in preparing this Guide.

Smart Metering

This term causes more confusion than any other simply because the term is too broad to be useful. Accordingly, it is not used in this Guide. In the context of the EPAct of 2005, the term simply means a combination of metering-related technologies, configured in a system, to support complex rates. That system includes the required metrology, calculation, storage, data communications, and data manipulation to acquire the billing determinants for rates that are more complex than a simple once-a-month, total-energy billing.

Unfortunately, some self contained, solid state, non-communicating meters are called "smart meters" by their suppliers. To add to the confusion, some communicating meters actually have very little, if any, intelligence in the meter because the "smart" manipulation of meter data occurs in some other point of the system, not in the meter. This approach is often called a dumb meter/smart network (in contrast with a smart meter/dumb (or transparent) network). The dumb meter/smart network approach minimizes the cost of each meter by moving the processing load (smarts) out of the meter and into the communication network where it can be more economically shared by many meters.

We urge readers to avoid the term Smart Metering in favor of terms that are more accurate and descriptive.

Time-of-Use (TOU) Rates

Time-of-use electric rates have existed since the late 1800s. Time-of-use rates were familiar to most wired telephone users-calls became cheaper after 9 PM and on weekends-well into the 1990s. The periods in which costs were higher were fixed well ahead of time, and were well known to all users. These high cost periods were a proxy for the times when electric demand (like high phone call volume) required the utility to provide additional, usually expensive system capacity.

Seasonal rates for residential customers are a form of time-of-use rate, averaged over months rather than hours. Seasonal rates do not require any form of advanced metering. Time-of-use rates have higher daily on-peak, shoulder, off-peak or weekend periods and do require either a complex multi register metering device with interval recording or a simpler metering device with network communication capability.

Different AMI vendors offer varying approaches. Some AMI systems report consumption upstream to a data collector every few minutes, and allow the concentrator accumulate that consumption into the shoulder peak, on-peak, and total energy “bins.” Some systems accumulate these consumption categories at or within the meter, and transmit these quantities infrequently for the entire billing period. Still other systems gather “interval data” and transmit a continuous succession of time-stamped readings taken every 15 minutes or every hour. The “head-end” or billing system then allocates those interval data to the correct rate for the customer. In some cases these data are also made available to the customer on the utility web site or by some other means.

More data is not necessarily better. More data may become a burden for the utility. It is far better to ensure that the system can provide all the detailed data that is actually needed now, and that the system is capable of providing whatever additional data may be needed in the foreseeable future. But it is not necessary or desirable to gather data that are not needed now. Very few utilities have a practical need for hourly data from all customers now. But many utilities can benefit from a system that is capable of supplying hourly data from any meter.

Utilities generally know the seasonal effects of weather-sensitive loads on their costs far in advance. Similarly, the utility has good data on how costs are likely to vary in any 24 hour period. This knowledge is the basis for time-of-use rates.

On top of these relatively predictable variations in the cost of service, many other factors cannot be established far in advance. Abrupt and unpredictable changes in weather or prolonged extremes of heat or cold, unscheduled loss of interconnection, transmission or major generating capacity, severe storms or natural catastrophes, and even anomalous market behavior all can create costs that are much higher tomorrow than they are today. Dynamic rates enable customers to respond to these conditions.

Dynamic Rates

Dynamic rates attempt to better reflect the hourly variation in system costs. Dynamic rates take many forms, but typically include an abrupt change in price with between 30 minutes and 24 hours of advance notice to consumers. Specific variations of dynamic pricing include:

- Interruptible rates, where the customer receives a financial incentive for his willingness to reduce or curtail usage on short notice. These rates are typically for industrial or municipal customers that can reschedule certain non-time-critical operations.
- “Superpeak” rates where, at some pre-announced time, a fixed high price (the superpeak) will go into effect. The dynamic superpeak rate often rests on top of a time-of-use rate structure, and is additive to it.
- Real-time pricing (RTP), where both prices and the time at which they take effect, are determined within hours of when they become effective. The term “real-time” is misleading, since in actual

practice there is an appreciable delay-usually a few hours-between when the RTP rate is established and published, and when it takes effect.

Dynamic rate forms obviously require one or more effective means of communicating with the affected customers. Phone calls or email may be sufficient for interruptible rates with large customers. This form of notice is not adequate for large scale residential implementations. The communication capability of the AMI system itself may provide notification options for a large number of smaller customers. Other options for notification can include paging, AM/FM sub-channel broadcast, evening TV news, the newspaper and email. If the rate is a fixed “superpeak” price, all that must be transmitted is the time at which it takes place. When it actually commences, an “ON NOW” message would allow customers to purchase and install control apparatus to automate their responses to the higher price. Activation signals for air conditioner load control provide an example “proxy” signal identical to a critical peak price signal. If, however, the dynamic rate is a form of RTP, the messages must also contain price information.

California is now examining the potential for “mandatory” dynamic critical peak pricing (CPP) for all residential and commercial/industrial customers. Historically, dynamic rates have not achieved much acceptance in the residential sector, with a few small but interesting exceptions. This may be because of customer perception of the apparent complexity of dynamic rates, or perhaps simply because such projects were not properly promoted or managed. California's “Statewide Pricing Pilot” tested consumer reactions, and has concluded that some customers find dynamic rates attractive and wish to remain on them.

Load Management (Load Control, Demand-Side Management)

Load management is the unilateral remote dispatch of certain non-essential or deferrable electric loads by the utility. These loads may be large loads, such as 100 hp irrigation pumps, or smaller loads like residential electric water heaters or swimming pool pumps. Load management requires a communication receiver and switch to be connected to the customer's end use load. Upon receipt of the signal from the utility, the load will be shut off for a certain time period, after which the load will automatically come back on.

Generally, customers volunteer for a utility load management program and in return they receive a fixed participation payment. The participation payment is generally not reflective of the load reduction contributed by each customer. With few exceptions, customers have no choice regarding when or for how long their devices are controlled by the utility. If customers become uncomfortable or don't like other aspects of the utility program, their only option is to stop participating.

Many fixed network AMI systems are capable of communicating control signals to load control devices that are also manufactured by the AMI supplier. This may or may not be an economically optimal approach. There is no compelling technical reason that the same communication system should be used for meter data acquisition and for load control. Existing public radio infrastructure (one and two-way paging, broadcast subcarrier, etc.), or existing utility radio infrastructure (RF-VHF), will quite often be a more economic choice for load management. So-called “smart” thermostats and programmable communicating thermostats (PCTs) are examples of available devices that contain radio receivers that allow the utility to remotely adjust the temperature set-point at participating customer locations.

Demand Response

Demand response is the reaction (usually a reduction of energy use) by a consumer at times of peak energy usage in response to a price signal or contract term. Demand response is a market based solution to address system pricing, supply or reliability conditions.

Induction Meter (electro-mechanical meter)

The induction meter evolved from the late 1800s to the early 1990s as the instrument of choice for electric revenue metering. This meter is also referred to as an electro-mechanical or Ferraris meter. It is essentially a motor in which the speed is related to both the current passing through the motor and the applied voltage. In revenue metering, the meter must be accurate to better than ± 2% or ±1% (depending upon regulatory requirements) over a specified load range. These meters are extremely reliable, but exhibit a tendency to run slower over time due to the buildup of friction in the mechanical elements. Induction meters have difficulty accurately metering very low loads. Finally, these meters are more susceptible to tampering than the solid state meters that are succeeding them.

AMR and AMI installations typically either replace all the existing induction meters with solid state meters as part of the overall process, or replace only those induction meters that are not suitable for retrofit and reuse with an AMR/AMI communication module.

Solid State Meter

Utilities are rapidly moving to solid state meters as they deployment AMR/AMI, replacing older induction meters. The solid state meters equipped with integral meter data communications are highly integrated and very reliable, and are cost competitive with the alternative of retrofitting older induction meters with “bolt-in” communication modules. Many utilities have found that the cost of retrieving an induction meter from the field, refurbishing the meter, fitting it with a communication module, recalibrating the meter and sending it back to the field is more than the cost of purchasing and installing a new solid state meter with integral communications, pre-tested and calibrated at the factory.

Decisions regarding metering strategy are very important because such a large number of meters is involved. That strategy is often shaped by the age and condition of the existing metering, and especially the depreciation status of the existing meter plant. The sudden removal and write-down of meters that may have been in use for 15 years, but were being depreciated over 30 or 50 years, can dramatically impact depreciation reserves, and income statements. Some state regulatory bodies have allowed continued recovery of the old metering system in rates to encourage adoption of AMI.

Communication Modules

The standard electric meter has no communication capability. It must be added. Electro-mechanical meters are not densely packaged, and typically contain enough empty space to allow a half-moon shaped communication retrofit module to be added. The retrofit module usually contains optical sensors that detect the revolutions of the rotating disk in the induction meter, and the module periodically (or upon request) transmits the accumulated total of disk revolutions, from which consumption is readily calculated. Modules are available from many vendors to fit most induction meters manufactured since the mid 1970s.

Some solid state meters are modular, and allow a communication board to be added at a later date. Today, however, the majority of solid state meters purchased have factory-installed communication, as arranged between the selected AMI supplier and the selected meter manufacturer. Five major manufacturers offer solid state residential meters. These companies and others also manufacture solid state meters for commercial and industrial applications.

APPENDICES

Excerpt of the Energy Policy Act of 2005

The text in this Appendix is cited verbatim from Title XII - Electricity, Subtitle E - Amendments to PURPA, starting on page 370 of the Act.

SEC. 1252. SMART METERING.

(a) IN GENERAL.-Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2621(d)) is amended by adding at the end the following:

“ (14) TIME-BASED METERING AND COMMUNICATIONS.-(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer each of its customer classes, and provide individual customers upon customer request, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

“ (B) The types of time-based rate schedules that may be offered under the schedule referred to in subparagraph (A) include, among others-

“ (i) time-of-use pricing whereby electricity prices are set for a specific time period on an advance or forward basis, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre-established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy costs by shifting usage to a lower cost period or reducing their consumption overall;

“ (ii) critical peak pricing whereby time-of-use prices are in effect except for certain peak days, when prices may reflect the costs of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

“ (iii) real-time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

“ (iv) credits for consumers with large loads who enter into pre-established peak load reduction agreements that reduce a utility's planned capacity obligations.

“ (C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively.

“ (D) For purposes of implementing this paragraph, any reference contained in this section to the date of enactment of the Public Utility Regulatory Policies Act of 1978 shall be deemed to be a reference to the date of enactment of this paragraph.

“ (E) In a State that permits third-party marketers to sell electric energy to retail electric consumers, such consumers shall be entitled to receive the same time-based metering and communications device and service as a retail electric consumer of the electric utility.

“ (F) Notwithstanding subsections (b) and (c) of section 112, each State regulatory authority shall, not later than 18 months after the date of enactment of this paragraph conduct an investigation in accordance with section 115(i) and issue a decision whether it is appropriate to implement the standards set out in subparagraphs (A) and (C).”

(b) STATE INVESTIGATION OF DEMAND RESPONSE AND TIMEBASED METERING.-Section 115 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2625) is amended as follows:

(1) By inserting in subsection (b) after the phrase “ the standard for time-of-day rates established by section 111(d)(3)” the following: “ and the standard for time-based metering and communications established by section 111(d)(14).”

(2) By inserting in subsection (b) after the phrase “ are likely to exceed the metering” the following: “ and communications.”

(3) By adding at the end the following:

“ (i) TIME-BASED METERING AND COMMUNICATIONS.-In making a determination with respect to the standard established by section 111(d)(14), the investigation requirement of section 111(d)(14)(F) shall be as follows: Each State regulatory authority shall conduct an investigation and issue a decision whether or not it is appropriate for electric utilities to provide and install time-based meters and communications devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs.”

(c) FEDERAL ASSISTANCE ON DEMAND RESPONSE.-Section 132(a) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642(a)) is amended by striking “ and” at the end of paragraph (3), striking the period at the end of paragraph (4) and inserting “ ; and” , and by adding the following at the end thereof:

“ (5) technologies, techniques, and rate-making methods related to advanced metering and communications and the use of these technologies, techniques and methods in demand response programs.” .

(d) FEDERAL GUIDANCE.-Section 132 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2642) is amended by adding the following at the end thereof:

“ (d) DEMAND RESPONSE.-The Secretary shall be responsible for-

“ (1) educating consumers on the availability, advantages, and benefits of advanced metering and communications technologies, including the funding of demonstration or pilot projects;

“ (2) working with States, utilities, other energy providers and advanced metering and communications experts to identify and address barriers to the adoption of demand response programs; and

“ (3) not later than 180 days after the date of enactment of the Energy Policy Act of 2005, providing Congress with a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007.”

(e) DEMAND RESPONSE AND REGIONAL COORDINATION.-

(1) IN GENERAL.-It is the policy of the United States to encourage States to coordinate, on a regional basis, State energy policies to provide reliable and affordable demand response services to the public.

(2) TECHNICAL ASSISTANCE.-The Secretary shall provide technical assistance to States and regional organizations formed by two or more States to assist them in-

(A) identifying the areas with the greatest demand response potential;

(B) identifying and resolving problems in transmission and distribution networks, including through the use of demand response;

(C) developing plans and programs to use demand response to respond to peak demand or emergency needs; and

(D) identifying specific measures consumers can take to participate in these demand response programs.

(3) REPORT.-Not later than 1 year after the date of enactment of the Energy Policy Act of 2005, the Commission shall prepare and publish an annual report, by appropriate region, that assesses demand response resources, including those available from all consumer classes, and which identifies and reviews-

(A) saturation and penetration rate of advanced meters and communications technologies, devices and systems;

(B) existing demand response programs and time-based rate programs;

(C) the annual resource contribution of demand resources;

(D) the potential for demand response as a quantifiable, reliable resource for regional planning purposes;

(E) steps taken to ensure that, in regional transmission planning and operations, demand resources are provided equitable treatment as a quantifiable, reliable resource relative to the resource obligations of any load-serving entity, transmission provider, or transmitting party; and (F) regulatory barriers to improve customer participation in demand response, peak reduction and critical period pricing programs.

(f) FEDERAL ENCOURAGEMENT OF DEMAND RESPONSE DEVICES.-It is the policy of the United States that 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, shall be encouraged, the 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 service markets shall be eliminated. It is further the policy of the United States that the benefits of such demand response that accrue to those not deploying such technology and devices, but who are part of the same regional electricity entity, shall be recognized.

(g) TIME LIMITATIONS.-Section 112(b) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(b)) is amended by adding at the end the following:

“ (4)(A) Not later than 1 year after the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility shall commence the consideration referred to in section 111, or set a hearing date for such consideration, with respect to the standard established by paragraph (14) of section 111(d).

“ (B) Not later than 2 years after the date of the enactment of this paragraph, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), H. R. 6-374 and each nonregulated electric utility, shall complete the consideration, and shall make the determination, referred to in section 111 with respect to the standard established by paragraph (14) of section 111(d).”

(h) FAILURE TO COMPLY.-Section 112(c) of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622(c)) is amended by adding at the end the following:

“ In the case of the standard established by paragraph (14) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraph (14).”

(i) PRIOR STATE ACTIONS REGARDING SMART METERING STANDARDS.-

(1) IN GENERAL.-Section 112 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C. 2622) is amended by adding at the end the following:

“ (e) PRIOR STATE ACTIONS.-Subsections (b) and (c) of this section shall not apply to the standard established by paragraph (14) of section 111(d) in the case of any electric utility in a State if, before the enactment of this subsection-

“ (1) the State has implemented for such utility the standard concerned (or a comparable standard);

“ (2) the State regulatory authority for such State or relevant nonregulated electric utility has conducted a proceeding to consider implementation of the standard concerned (or a comparable standard) for such utility within the previous 3 years; or " (3) the State legislature has voted on the implementation of such standard (or a comparable standard) for such utility within the previous 3 years."

(2) CROSS REFERENCE.-Section 124 of such Act (16 U.S.C. 2634) is amended by adding the following at the end thereof:

" In the case of the standard established by paragraph (14) of section 111(d), the reference contained in this subsection to the date of enactment of this Act shall be deemed to be a reference to the date of enactment of such paragraph (14)."

1 Revenue Metering Loss Assessment, EPRI, Palo Alto, CA, Arizona Public Service Co., Phoenix, AZ, National Grid USA, Worcester, MA, South Carolina Electric & Gas Co., Columbia, SC, and Baltimore Gas & Electric Co. Baltimore, MD, 2001. 1000365

2 Supervisory control and data acquisition

3 Energy Policy Act of 2005, Subtitle E, Section 1252 (f).

4 As a corollary to this, a utility can make a very quick and coarse estimate of the AMI benefits by multiplying by about 2.5 the total cost of its meter reading activity. Note that this estimates the benefit in traditional utility operations only. Other benefits are additional, such as demand response.

5 Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them, DOE report to Congress pursuant to EPAct 2005, February 2006. See http://www.electricity.doe.gov/documents/congress_1252d.pdf.

6 Statewide Pricing Pilot Summer 2003 Impact Analysis, Charles Rivers Associates, August 9, 2004.

7 Statewide Pricing Pilot (SPP): Overview and Design Features, presentation by Roger Levy, Levy Associates, at a joint workshop titled "Advanced Metering Results and Issues", Sacramento, California, 30 September 2004.

8 ibid

9 This example is fictional. It was assembled by Plexus Research using data from several utilities, normalized for size and type (electric, gas, water). Any apparent relationship of this example to any actual utility is purely coincidental.

10 These costs are the amounts paid to the AMI supplier(s). Amounts not paid to the AMI supplier(s) are estimated and included in the benefit estimates, because they are most readily identified and estimated during the exploratory process of discovering benefit potential.

11 Most recently and notably, the California Statewide Pricing Pilot.

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