Metering Strategy:
Long Term Choices in Uncertain Times

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Emergence of Metering Strategy

Not long ago, it was rare for an electric utility to replace most of its meters in a single project. Evolution of technology and the energy markets is making this not only justifiable, but the best path for some utilities. A decision with such a large financial impact is not taken lightly. It must rest on a thoughtfully developed metering strategy.

Metering historically has not been regarded as a strategic issue for electric utilities. Regulation has dictated what a utility can sell, to whom and for how much. The meter's purpose was simply to measure the amount of energy sold so the bill could be rendered. It was just the "cash register". Energy industry restructuring is changing this, putting some energy companies on a footing similar to other retailers. If the traditional monthly energy reading is replaced with advanced meter data, the meter becomes the means for knowing not just how much the customer purchased in a month (or two), but also when it was used. This key information helps the utility to discern what the energy is used for, and often why.

Understanding customers' use of the product allows a business (any business) to tailor its product offering to customers' specific needs, enabling a range of new services. Energy examples include an energy "sale", a selection of multi-tiered rates (e.g.: time-of-use), managed-load rates, bulk payment rates, peak-responsive or "dynamic" rates, prepayment rates and others. In addition, advanced metering can support wholesale energy information services, provided by the distribution company to independent energy retailers. Examples include aggregated load profiles by customer classes, billing services and custom analyses.

Finally, understanding energy consumption patterns in more detail allows a distribution company to better track how its distribution resources are used. Instead of estimating circuit loads by feeder and region, season and time of day, the distribution company can know the loads with certainty. Distribution asset utilization can be significantly improved.

Metering has become a strategic resource that directly affects the utility's ability to understand customer needs and to respond creatively—or even adequately—to changes in the market. Metering strategy encompasses measuring customer energy usage and recovering the data to the utility. This includes *metering* and the means of *meter reading*, which often becomes remote automated meter reading (AMR).

Strategy Context

Metering strategy does not stand alone, defining its own needs and goals. The metering strategy must serve the overall goals and directions of the utility. The overall company strategy defines the context for more the specific strategies in all the key functional areas of the company: metering, information systems, distribution, supply, etc. This overall strategy will answer the most basic questions related to planning and operating the utility. Those related to metering include:

- What business(es) do we want to be in?
- What services to we want to provide? To whom?
- When do we expect to begin these businesses and services?
- What data do we need to do those things? How often do we need the data?

The Metering Questions

A metering strategy must resolve the many questions that follow from the utility's overall strategy. Four presently loom large for most electric utilities.

- Should we buy induction meters or electronic meters for single-phase service?
- What meter function(s) should we deploy? Should we buy simple kWh meters, or do we need something more, like time-of-use (TOU) or demand meters, or something that can serve multiple functions?
- Should the meters include AMR? Or is having the ability to upgrade later enough?
- When should we deploy whatever metering we think we will need? We know it can take several years to change our metering resources and capacity. Is it important to start the wheels turning early? How early? Will we "migrate" or do a wholesale changeout?

Answering these questions effectively requires clear strategy. In the absence of strategy, the utility typically will do what makes sense in the near term, potentially compromising its long term interests.

The rest of this paper describes some basic elements and rationale of metering strategy for electric utilities in North America. To give meaningful insight in the available space, the paper leaves out many details and uses examples to illustrate selected elements.

The Starting Point

A strategy addresses how to get from where we are to where we want to be. Defining where we are now sets the foundation. Major parts of this are:

- The age and function of the existing meter stock.
- The age and capabilities of existing meter reading systems.
- Capability and flexibility of existing information technology (IT) systems supporting metering and the uses of meter data.
- Existing commitments to stakeholders, generally including customers, members / shareholders and regulatory or other governing bodies.
- Regulatory requirements, as applicable.

Any or all of these can critically affect metering strategy. For example, if the customer base has grown significantly in the last decade, the undepreciated value of the new meters can be a substantial obstacle to an acceptable business case for meter upgrade or replacement. And there will be little point in collecting valuable new meter data if the utility's IT systems cannot process it to produce that value.

Where We Want to Be

The end point is a moving target, always five years away (or whatever planning interval the utility chooses). The best we can do is to get close. But there will always be new requirements, new technologies, new challenges, new problems to solve—always. A good strategy describes broadly where we want to be and how we will get there, and is periodically revised to keep it in accord with evolving corporate objectives.

Strategic Choices

Completing a metering strategy involves many choices that differ from utility to utility. Here we will use two for illustration that apply to most utilities.

- Projected service requirements and timing.
- Risks and risk mitigation.

Projected Service Requirements & Timing

We cannot decide what metering we need or want without first deciding what metered information we will need to meet our customers' service requirements and expectations. As one example, let us consider rates.

A single monthly energy consumption reading has been sufficient for service to most single-phase utility customers for many years. Many industry watchers now believe that TOU rates will soon become far more common than they are now. History has shown, and recent deployments have confirmed, that TOU rates can be a "good thing". Some customers respond to well-designed TOU rates by modifying their energy consumption in ways that help moderate energy price variations and benefit the environment. Furthermore, many customers prefer a TOU rate once they have experience with it.

The corporate strategy defines broadly what categories of service the utility will provide, and may specifically identify TOU, demand, dynamic or other rates as future requirements. The challenge for metering strategy is to decide *now* how we will manage metering assets to support those services in the coming years. Historically, metering assets cannot be changed quickly, and the business environment has not required quick changes. The evolving energy business may require more metering flexibility. Utilities—especially those with aging meters—have an unprecedented challenge and opportunity now to position their metering resources for the future.

Technology provides the ability to deploy meters that can be inexpensively reprogrammed in place to provide selected meter data. But this flexibility cannot anticipate all possible needs. We still have to make some risky decisions, which raises the next issue …

Risks & Risk Mitigation

People often discuss the risks of an AMR deployment, and point out the value of creating plans to mitigate the anticipated the risks. This certainly is an important aspect of any major project in metering, AMR or any other area. More strategic is the comparison of the risks of alternative paths, before one path is chosen.

Suppose, for example, that we are considering deploying AMR to a customer base of urban electricity users. How do the risks of retrofitting AMR to existing meters (replacing some meters) compare to the risks of replacing *all* the meters? And how do those options compare to the risks of doing nothing now and just waiting to see what next year's technology will bring?

The financial impacts are so large that it's very important to get this right the first time. To illustrate this, suppose a utility retrofits to its induction meters an AMR system that returns only total monthly energy (kWh) consumption. The utility knows there is a risk that it may need to do more complex rates in the future, but decides to do the simpler kWh-only system anyway. Now further suppose that five years later the utility finds that, indeed, it must offer TOU service to all its customers. This will require replacing the AMR system. What are the financial consequences of this decision path, and how can we quantify the risk?

To simplify our illustration, let's assume that the utility deploys its kWh-only AMR system now, in 2003, and that interest rates and inflation are both zero, so there is no time cost of money.

Case 1a - 2003
The utility's business case for this 2003 project includes, among other things, costs to remove and replace (R&R) the meters and the cost to perform required testing after installing the AMR modules. Assume that the benefits outweigh the costs and create a net benefit to ratepayers and owners. The utility proceeds with the deployment.

Case 1b - 2003
A more capable metering and AMR system that supports TOU metering is more costly to buy and to install. These costs would be partially offset by some immediate benefits, not including ability to do TOU, which is not required in 2003. The 2003 business case for this system is positive but, compared to Case 1a, it's extra benefits are not as great as its extra costs, so it is less favorable—the "payback" is longer. The simpler system is projected to produce more value sooner, based on what is known now. On that basis the utility chooses the simpler system.

Case 2 - 2008
When the TOU requirement emerges in 2008, the utility must replace the simpler AMR system with a more capable one. The 2008 business case itemizes the costs and the benefits of the new system. It includes two major costs that would have been avoided by choosing Case 1b in 2003. For the moment, we'll call these "reset" costs. One is the recurrence of the same R&R and testing costs incurred in 2003. The other is the undepreciated value of the first AMR system, which must be offset by additional benefits to achieve a positive business case in 2008. These two costs are substantial and may constitute millions of dollars that otherwise would benefit the utility's ratepayers and its members or shareholders.

The Decision in Retrospect
Deciding to deploy the more capable AMR system in 2003 would have been equivalent to buying insurance to cover the risk that TOU capability (or some other function supported by the more capable AMR system) would be required later. The insurance "premium" is the difference between the Case 1b and Case 1a results. Paying this "premium" in 2003 avoids

later incurring the two reset costs. Estimating the reset costs in 2003 and comparing them to the “premium” allows the utility to make an informed selection between the simpler and the more capable AMR systems in 2003.

Of course, this simple example leaves out many details. Typically there are multiple future scenarios: nothing changes, TOU metering becomes necessary, demand metering becomes necessary (or just valuable), and so on. And there are multiple options: do nothing, do something, do even more, and so on. Each option has its own “reset” costs in each scenario, and the details differ substantially among utilities. Many utilities examine the alternatives and decide that the “premium” is high. They choose to do nothing now, or to deploy basic AMR and metering. Others examine the same criteria and choose more capable AMR and/or advanced metering. Getting it right the first time avoids the penalties of “reset” costs, which can be so high that it won’t be economically practical to change metering and AMR assets for a decade or longer after an AMR project. Examining the alternatives and quantifying the risks helps to make the right choice and to mitigate the risks.

Contract Provisions

Once the basic approach to metering and AMR is chosen, contract provisions can effectively mitigate many additional risks. The contract’s terms for incremental orders, support, termination, warranty and other aspects all can serve the utility’s needs without unduly burdening the supplier. The experience of Plexus Research is that technically enlightened contract clauses and agreements can retire perceived risks for all parties.

Suppliers have considerable experience in these provisions because they typically engage in several large contracts each year. But a utility often has little experience because a single utility won’t normally conduct a large metering and AMR project more than once every ten to twenty years. Having this experience on its “side of the table” during contract negotiations gives the utility value far exceeding its cost in favorable project terms and risk mitigation.

Determining Factors

Many factors guide the choices of which meters, how many, what AMR devices, etc. Here we mention just a few to illustrate the roles of these factors in metering strategy.

Life, Accuracy & Stability of New Meters

Buying new meters now, especially single-phase meters, raises questions that did not come up ten years ago. Induction meters have a long track record that gives users high confidence in their future performance. The latest generation of meters is all-electronic and lacks a comparable record. Polyphase meters have been electronic for more than ten years but, due to technology improvements during that time, the experience with ten-year-old (or even five-year-old) electronic meters doesn’t reveal much about how new electronic meters will perform or how long they will last. Utilities understandably sense some risk in the new generation of electronic meters.

The lack of track record is not a good reason to avoid the new electronic meters. Costs are now competitive with induction meters. They provide significant benefits in improved accuracy, reduced and simplified testing, lower inventory, greatly increased flexibility, and other aspects.

The role of metering strategy is to garner these benefits for the utility and its customers while adequately mitigating the risks and uncertainties.

Deployed Cost & Benefits

Certainly the deployed cost and benefits of metering and AMR are pivotal in deciding what and how much metering and AMR to deploy. Estimating the benefits and costs is a key step that, if done well, provides not just the numbers but also essential insight to guide metering strategy. This is illustrated by the example above where three business cases provide quantitative basis for a long-term metering and AMR choice.

Metering & Other Strategic Initiatives

Of course, metering strategy is not independent of the other strategies a utility will have, and it is imperative to consider other utility initiatives and goals when creating the metering strategy. The other utility strategy that is most central to supporting overall corporate operations is IT strategy. Again, an example will illustrate the point.

> A utility was assembling an AMR business case, itemizing the benefits in many utility departments and operations. The AMR team estimated that AMR would advance cash flow by 4 days. If a utility's gross annual revenue per meter served is, say, $1,200, this benefit is about $1 per meter per year at an assumed internal rate of return of 7%. That is, it's $1 million per year for a utility with a million customers. This is not a large benefit, but it is one of many that, taken together, produce significant value for a utility.
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> During executive review of the business case, utility management decided that the value of advancing the revenue stream must be omitted from the claimed list of benefits. They reasoned, correctly, that the cash flow advance cannot be achieved without modifying the billing system. Since the cost of such modifications was not included in the AMR business case, it is incorrect to include the benefit.
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> Similar logic leads many utilities to remove many AMR benefits from their analyses because they depend on other utility systems, operating procedures and capital projects. This logic has compromised many AMR business cases.

A more balanced approach is to acknowledge that the billing system will almost certainly be modified or upgraded in the next five years for other reasons anyway. This work will have its own compelling business motivation and cost/benefit analysis. The relevant cost for the AMR business case is the *incremental* cost of advancing the billing process, not the whole project cost. This can be estimated by exploration with IT managers, and often is indiscernibly small. If a dollar figure can be identified, the benefit of the cash flow advance can be pro-rated between the AMR business case and the later billing system cost/benefit analysis. Applying this approach to the various AMR benefits that depend on other utility activities recognizes the real benefits AMR provides and the real costs of achieving them. This can substantially improve the AMR business case and the validity of overall metering strategy.

Conclusion

Metering strategy is the overall vision and plan for measuring customer energy usage and gathering the measurements into the utility's business systems. This process is one of a small number of processes that are central to producing value for the utility's stakeholders: the customers, members, shareholders and others. The information embodied in the meter data defines the ways the utility can serve its customers. Meter data shape the products the utility can sell.

A well-founded metering strategy will be based upon many factors. It will address both metering and meter reading and will leverage the best of the industry's experience in these disciplines. The metering strategy does not "stand alone". It is responsive to overall corporate goals and is interdependent with the strategies for other major processes in the utility. Once a metering strategy is in place, new things become possible in other parts of the company: new customer services, system planning approaches, outage management methods, etc.

Creating a business case for new metering and meter reading is complex because metering affects so many utility operations, and because it requires projecting future impacts. Experience has identified ways to correctly incorporate benefits that often are missed during planning, improving the validity of overall strategy and of individual decisions.

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Plexus Research is an engineering and business consulting firm serving the energy industry in technologies for utility interaction with customers. The firm's expertise includes metering, AMR, prepayment and load management, and related technologies and business issues. Incorporated in 1983, Plexus is the energy industry's premier independent resource in these specialties and is highly regarded for its objectivity, integrity and quality of results. In its 20 years of service, Plexus has served hundreds of prominent and emerging technology suppliers, utilities and institutions.