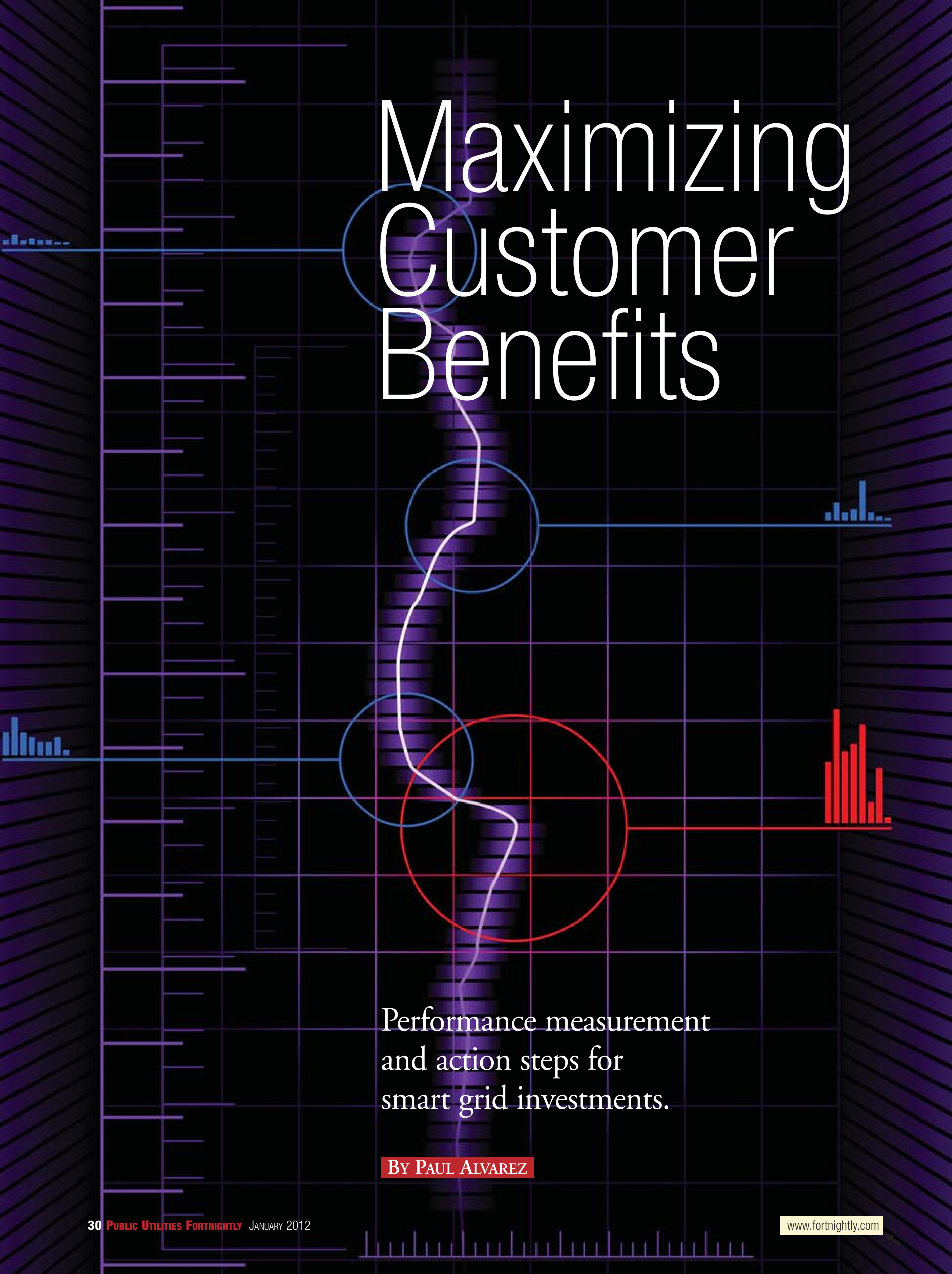

Maximizing Customer Benefits

Performance measurement and action steps for smart grid investments.

By Paul Alvarez

Scores of investor-owned utilities (IOUs) have invested hundreds of millions of dollars to improve distribution capabilities. Now those utilities are beginning to consider how best to utilize the new capabilities. Other IOUs are in testing and strategy development phases. And regulators are considering what role they should play in encouraging IOUs to make prudent grid investments while minimizing risks and maximizing benefits for distribution customers.

As more utilities make smart grid business cases public, and as more independent smart grid performance evaluations are completed,[1] a picture of the principal smart grid customer benefits, costs, risks, and drivers is emerging. Many observers, from the Maryland PSC to the governor of Illinois, have concluded—correctly in the author's opinion—that the business case for the smart grid is far from being a "no brainer," and that significant post-deployment efforts are required if benefits are to be maximized. It's becoming increasingly clear that most investments in smart grid capabilities are different from traditional generation, transmission, and distribution investments in one fundamental respect: commissioning doesn't automatically translate to customer value.

Traditional utility investments are made, more often than not, to replace aging assets or to meet increases in demand for capacity. Once the case for investment is made, procurement proceeds, assets are placed into service, and customers enjoy the value in terms of improved reliability, reduced emissions, and similar benefits. Many, if not most, smart grid capabilities are different in that utilities must make concerted, post-commission efforts—in organizational changes, operating process redesigns, and customer program development—to maximize value for customers. Variation in time-of-use pricing program designs and adoption rates will impact the level of benefits received by both participating and non-participating customers. The extent and design of interactive volt/VAR control deployment will impact the degree of improvement in distribution efficiency. And the vigor and timing of meter-related staff reductions will impact the amount of O&M savings realized.

To summarize, smart grid benefits are driven in large part by utilities' design and post-commission implementation choices. In the case of IOUs, these choices are in turn driven largely by regulation. As a result it's appropriate for customers to ask some tough questions related to the smart grid:

- Is my utility maximizing the value of smart grid investments? And how would I know?
- Who should take the lead in measuring benefits—regulators or IOUs?
- What can regulators do to encourage IOUs to make prudent investments and maximize benefits for customers?
- What can IOUs do to maximize benefits for customers?

Answering these questions will require regulators to establish the conditions necessary to encourage and enable IOUs to maximize customer benefits, and IOUs must make the organizational and operational changes—and develop the customer programs—necessary to maximize those benefits. Failure on the part of either party will result in missed opportunities, needlessly long customer payback periods, and ineffective use of smart grid investment grants funded by U.S. taxpayers.

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Paul Alvarez is a principal and utility practice leader at MetaVu Inc. He led two independent evaluations of smart grid deployments for Xcel Energy and the Public Utilities Commission of Ohio.

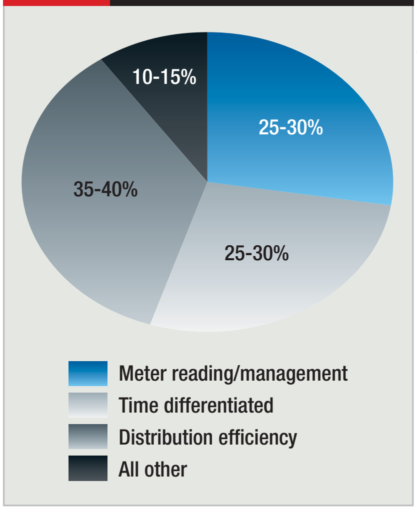
Measuring Benefits

Though safety and environmental benefits have been documented in smart grid implementations, three types of benefits appear to be the most tangible for customers: economic benefits, reliability improvements, and customer service enhancements.

- *Economic Benefits:* Publicly available information from comprehensive and independent evaluations of smart grid deployment performance, combined with reviews of publicly available smart grid business cases, make it fairly clear that 80 percent to 90 percent of the economic benefits of full smart grid deployments available to customers come from three sources: meter reading and management savings; time-differentiated rate implementation; and distribution efficiency. Though every utility's experience will vary with situational characteristics and deployment variables, measuring economic benefits in just these three areas is likely to satisfy the 80/20 rule *(see Figure 1)*.

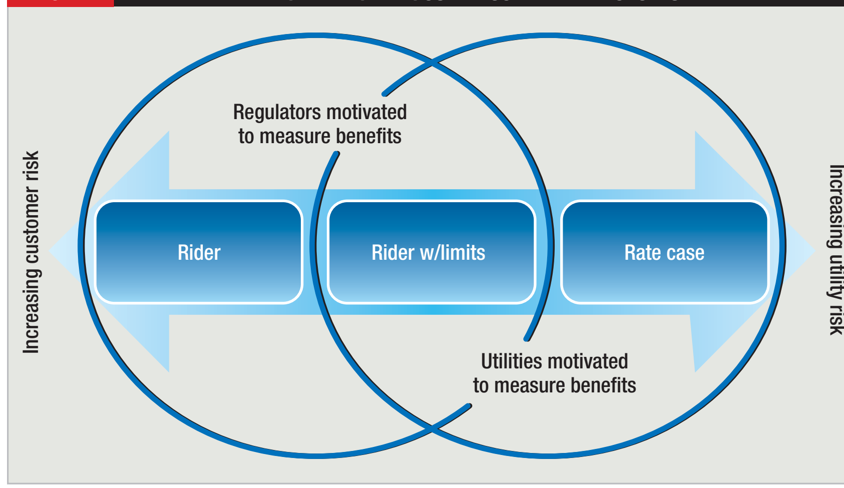
Measuring meter reading and management savings from AMI deployment is relatively straightforward. The accounts of departments for which reductions in force are anticipated as a

FIG. 1 TOP SMART GRID BENEFITS



Source: Author's analysis, MetaVu Inc.

FIG. 2 SMART GRID COST RECOVERY APPROACHES



Source: Author's analysis, MetaVu Inc.

result of smart grid deployments can simply be compared pre- and post-deployment to quantify savings. Dollar amounts can be translated into metrics for additional precision, including, for example, meter reading and management costs per meter.

AMI deployments also offer value through time differentiated rates. The most appropriate performance measurement approach should consider the circumstances under which such rates are offered. For example, performance can be measured through customer adoption percentage—likely more appropriate in the case of voluntary or opt-in time differentiated rate offers—though utilities might argue that time differentiated rate participation is only partly under utility control. Another approach is to measure overall impact on demand relative to a baseline—likely more appropriate for default or opt-out rate offers, but useful for measuring the performance of voluntary rate offers as well.

Getting customers to adopt time-differentiated rate offers on a voluntary basis has proven extremely challenging, as most designs increase customer risk and effort. The peak time rebate approach, which features carrots instead of sticks, warrants strong consideration as a result. Some of the research on time-differentiated rate designs indicates that carrot approaches can be just as effective as stick approaches in modifying customer usage behavior.[2]

Integrated volt/VAR control offers significant improvements in aggregate distribution efficiency, reducing the usage of customers located on treated feeders by a couple of percentage points through reduced voltage and optimized power factor. Performance can be evaluated by measuring energy accepted by substations and comparing it to sales volumes billed. Such a measure would also include metering errors, billing errors, and theft, but these revenue capture issues are also subject to improvement through smart grid investments and warrant measurement and performance management efforts.

■ *Reliability Improvements:* Most smart grid deployment plans include improved capabilities in distribution automation and status monitoring designed to improve grid reliability. Independent assessments have confirmed that significant improvements in reliability—moderate double digits as a percentage—are indeed available from these capability improvements. Existing reliability metrics such as SAIDI, SAIFI, and MAIFI[3] are likely sufficient to measure these improvements over time, though observers are cautioned that improvements in SAIDI (resulting from increased sectionalization, for example) can come at the expense of MAIFI performance. "Customer minutes out" is another performance metric that warrants consideration for this reason. Of course normalization for weather will still be an important component of reliability measurements.

Smart grid benefits are driven in large part by utilities' design and post-commissioning implementation choices.

Beyond statistics, however, it's difficult for individual customers to perceive even fairly significant improvements in reliability. The issue is simply one of scale; a 99.95 percent reliability rating translates to only 4.4 hours of customer outage a year. Even a 20 percent improvement on 4.4 hours of outage amounts to less than an hour's improvement annually. This fact, combined with the infrequent nature of outages, makes reliability improvements extremely difficult for customers to perceive.

■ *Customer Service Enhancements:* Customer service enhancements, generally made possible by AMI and two-way meter communications, can be difficult to measure. Quantifying the percentage of eligible customers that access a new capability is a reasonable metric for some enhancements, such as in the case of detailed energy usage information being made available via secure web page. However performance on other potential customer service enhancements isn't so easily measured. Consider for example, a proactive outage information service. Such a service would combine smart grid capabilities with today's communications technologies to text or e-mail information on outages to affected customers. Simple descriptions of new customer service enhancements implemented as part of smart grid deployments might have to suffice as a yes-or-no performance measure in some instances, with emerging best practices serving as useful benchmarks as to what is feasible and valuable. Another service enhancement that a subset of customers would appreciate is prepayment; AMI provides capabilities that facilitate the operation of pay-as-you-go programs.

Communicating Benefits

Smart grid benefits can be significant in the aggregate but insufficiently large for individual customers to perceive. Even customer service enhancements, which one might consider to be readily perceptible, are known only to customers that have accessed them or been exposed to them. And even these customers might not relate the enhancements to smart grid investments. Accordingly, documentation and communication of benefits to customers should be a conspicuous component of post-deployment optimization plans and is critical to confirming smart grid merits and value to customers.

One way to think about smart grid benefit communications: If a benefit isn't communicated, it's as if the benefit had never been created from a customer's perspective. Even the U.S. government understands this concept; what driver hasn't seen a road construction project adorned with "this project funded by the *American Reinvestment and Recovery Act*" signs?

This isn't to suggest that communications shouldn't be conspicuous before smart grid deployment as well. In fact, providing stakeholders with realistic expectations about smart grid value and capabilities before investments are made is perhaps more critical than post-deployment communications. Stakeholder engagement can help utilities prioritize smart grid investments by understanding the value constituencies place on various capabilities and benefits.

Benefits and Cost Recovery

Three distinct approaches to smart grid investment cost recovery appear to be emerging: special-purpose riders; special-purpose riders with limits based on anticipated economic benefits; and traditional rate case prudency reviews.

The approach to smart grid cost recovery has significant implications for the roles regulators and IOUs should play in measuring and communicating benefits. Figure 2 depicts the relationship of each approach on the customer-utility risk continuum, and what it means for leadership of benefit measurement and communication efforts.

Some commissions have authorized special-purpose riders to encourage utilities to make smart grid investments. In many cases regulators specify rider characteristics designed to help manage and control smart grid deployment costs. However these riders typically contain few or no quantified provisions designed to maximize benefits for customers. Accordingly, smart grid riders can result in somewhat greater risk to customers than other smart grid cost recovery approaches. In these situations regulators are advised to take a leading role in ensuring that post-deployment benefits are measured, maximized, and communicated to customers.

Other commissions have authorized special purpose riders with built-in customer risk management features. To date, these features have consisted of revenue requirement limitations based on economic benefits that IOUs have suggested would be generated by smart grid investments. Anticipated economic benefits recognized in this manner have included smart grid-related reductions in operations and maintenance spending, improvements in revenue capture, and reduced depreciation expenses associated with beneficial deferral of capital benefits.

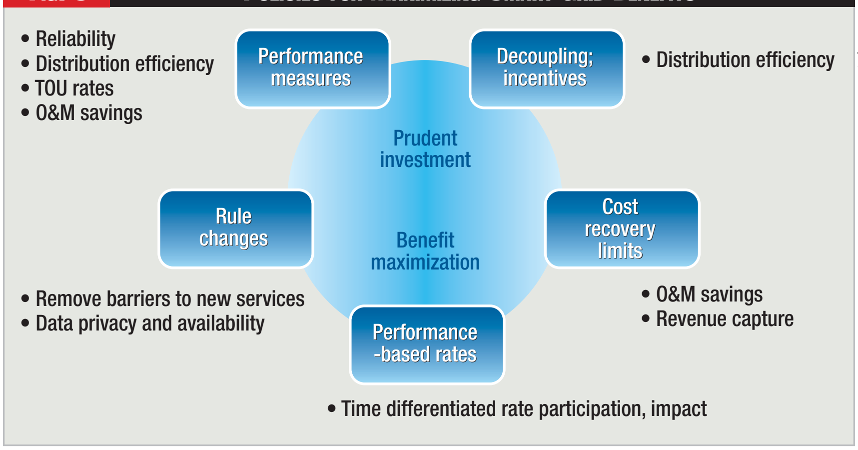
Some types of smart grid capabilities reduce sales volumes and therefore an IOU's opportunity to earn its authorized rate of return.

An interesting attribute of this approach is that it balances customer and utility risk for post-deployment performance. In so doing, utility shareholders are exposed to increased risk in exchange for increased profit opportunities. To the extent an IOU fails to achieve predetermined levels of benefit, shareholders pay the difference. And to the extent an IOU delivers greater benefits than anticipated, IOU shareholders benefit. In the "rider with limits" case, both regulators and utilities are motivated to measure, maximize, and communicate benefits to customers.

Still other commissions have elected to take no pre-deployment stance on the recovery of smart grid investments, preferring instead to subject IOUs to traditional prudency reviews as part of routine rate case proceedings. This approach can serve to discourage IOU investment in all but the most traditional grid capabilities, as cost recovery of investments in capabilities later determined to have been imprudent could be disallowed. However the approach does minimize risks for customers.

Combination approaches are also available; the Illinois legislature recently approved an act[4] that offers the state's IOUs the benefits of a rider but retains prudency reviews and adds a performance-based ratemaking component. In the event IOUs fail

FIG. 3 POLICIES FOR MAXIMIZING SMART GRID BENEFITS



Source: Author's analysis, Metavu Inc.

to hit reliability and revenue enhancement targets, authorized rates of return on smart grid investments can be docked 500 basis points. However, the performance-based measures incorporated in the Illinois legislation fail to include any of the top three economic benefit opportunities—meter reading and management savings; time-differentiated rate implementation; and distribution efficiency.

In smart grid cost recovery frameworks that put utilities at risk, IOUs are encouraged to take a leadership role in smart grid benefit measurement, maximization, and communication, as doing so can result in a significant reduction in cost recovery risk.

Action Steps for Regulators

Though their numbers appear to be dropping, there exist some regulators and staffs that are hesitant to provide IOUs with incentives or change rules to encourage activities and investments that arguably could be categorized as IOUs' social responsibilities. Although this sentiment is understandable, it ignores the reality of the regulatory compact and IOUs' responsibilities to their shareholders.

Regulators increasingly are embracing the concept of shared responsibility for shaping electric distribution systems and services in a manner that creates the greatest value for utility customers for the least cost. Open and informal interactions with multiple stakeholders are likely to lead to the best outcomes and the most appropriate rulings and rule changes required to release the potential of the smart grid.

The reality is that post-investment regulatory actions will be required to ensure that the benefits of smart grid investments are maximized for customers. Several types of smart grid benefits increase IOUs' risk or reduce their opportunities to earn authorized rates of return—or both—particularly in states where decoupling hasn't been introduced. Other types of smart grid benefits will accrue to shareholders until recognized in a general rate case. Further, regulatory rule changes might be required to enable other types of smart grid benefits. Examples of smart grid capabilities and benefits that should prompt regulator action include:

- Distribution efficiency and time-differentiated rates will reduce utility sales volumes.
- Operations and maintenance expense reductions and revenue capture improvements accrue to shareholders until recognized in a general rate case—absent special cost recovery mechanisms.
- Some anticipated economic benefits might not be possible without thoughtful regulatory rule changes.
- New regulatory rules might be required to encourage certain types of customer service enhancements.

Some types of smart grid capabilities reduce sales volumes and therefore a utility's opportunity to earn its authorized rate of return, absent decoupling or some sort of incentive opportunity. In fact two of the three smart grid capabilities that yield the greatest economic benefits—distribution efficiency and time differentiated rates—will reduce utility sales volumes. Prepayment programs are also likely to reduce sales volumes. Utilities will understandably be reluctant to maximize such benefits. Some would argue that investments in distribution efficiency, time differentiated rate capabilities, and even prepayment programs are the economic equivalent of demand-side management (DSM) programs because, like DSM programs, the utilities make the investment and take the revenue risk while customers benefit. To address utility disincentives to maximizing these customer benefits, regulators could consider decoupling or performance-based ratemaking.

Smart grid benefits can be significant in the aggregate, but insufficiently large for individual customers to perceive.

On the other side of the coin, some types of smart grid benefit accrue to shareholders until recognized in a general rate case. Examples of these types of benefits include operations and maintenance spending reductions—*i.e.*, in meter reading—and improved revenue capture—for example, through improved meter accuracy or reduced theft. Regulators are encouraged to consider revenue requirement reductions, such as the rider limitations described earlier, to ensure customers receive economic benefits in the absence of a timely rate case that would recognize such benefits.

Some smart grid capabilities might not deliver benefits with-

Smart Grid Performance Measurement

Several sets of guidelines are emerging as the standards in smart grid performance measurement. "A Methodological Approach for Measuring the Costs and Benefits of Smart Grid Demonstration Projects," available from The Electric Power Research Institute,5 provides a valuable guide to cost and benefit quantification. The "Smart Grid Maturity Model," developed by the U.S. Department of Energy and Carnegie Mellon University, is ideal for assessing the ability of a utility organization to maximize the value of smart grid investments; the model examines leading indicators, such as the existence and sophistication of smart grid-related operations planning, training, performance measurement, incentives, and similar processes. And the Environmental Defense Fund has weighed in with "Evaluation Framework for Smart Grid Deployment Plans," which describes a relevant set of outcome reporting metrics—lagging indicators—that could serve to benchmark any electric distribution company's performance improvement efforts, regardless of smart grid status.

State regulators have been busy considering smart grid benefits as well. Several orders and investigative dockets provide helpful background for regulators (and IOUs) considering smart grid benefit maximization:

Illinois Statewide Smart Grid Collaborative Report, Sept. 30, 2010, including an excellent summary of smart grid cost recovery issues.

Colorado PUC order C11-0406, concluding an investigatory docket that addressed smart grid and advanced metering technologies and associated benefit maximization.

California PUC order 08-12-009, addressing access to, and the privacy and security of, customer energy usage data.

Oklahoma Corporation Commission order 576595, approving Oklahoma Gas and Electric's smart grid rider with adjustments for anticipated benefits, and mandating customer communications.

Illinois Power Agency Act 097-0616, which reduces the authorized rate of return on smart grid investments in cases in which certain anticipated benefits aren't achieved.*–PA*

out thoughtful regulatory rule changes. For example many utilities included remote service disconnect capabilities in their AMI designs, along with associated economic benefits in their business cases. Most states' rules require utilities to contact customers before service is disconnected for reason of non-payment. In most of these states, this requirement has been prescribed to mean in-person contact, versus a phone call, generally to offer a final opportunity to meet a payment plan obligation, or to post a disconnection notice. As a result of these requirements, remote disconnect capabilities don't result in cost savings in instances of non-payment. If thoughtful compromises can't be reached, associated cost savings won't be realized.

Other smart grid capabilities might require new regulatory rules. One of these is proactive outage information, in which enhanced smart grid outage management information can be combined with automated outbound phone messaging, e-mailing, and texting capabilities to keep customers informed about the status of an outage. Although this might sound like a valuable service, customers could come to rely upon the accuracy of such communications and take certain actions based on them. It's easy to envision how inadvertent inaccuracies in such communications could cost customers money; consider a customer with a freezer full of food who fails to receive a notice about an outage while out of town on vacation or business. Utilities are understandably reluctant to offer new services that might subsequently be transformed into utility obligations and result in potential liabilities. New regulatory rules might help overcome utility resistance to such service improvements.

Another example of a smart grid capability that will require new rules to maximize customer benefits is increased data availability. Regulators will need to establish rules about the privacy and security of energy usage data, as well as rules related to accessing such data by customers and authorized third parties.

To summarize, regulators have many tools at their disposal to encourage utilities to make prudent investments in distribution capabilities while minimizing risks and maximizing benefits to customers.

Utilities are understandably reluctant to offer new services that might transform into obligations and liabilities.

Action Steps for IOUs

Regulators and customers will demand that the benefits of smart grid investments are maximized, and utilities should understand this and act accordingly. Increasing use of emerging measurement standards is contributing to a growing body of knowledge around electric distribution business performance, going beyond reliability and incorporating everything from distribution efficiency and customer service improvements to time differentiated rate participation and impact. Utilities can expect that their feet will be held to the fire.

Utilities will need to make significant organizational and operational changes to truly maximize the value of smart grid investments. From service centers to distribution control centers, from engineering to marketing, and from distribution capacity planning to business systems, roles and responsibilities will need to be

FIG. 4 CHANGE MANAGEMENT COMPONENTS

Suggested components of change management plans for smart grid deployment.

Source: Author's analysis, MetaVu Inc.

modified, operating processes will need to be changed, and programs will need to be developed. A few examples:

- Performance-based ratemaking might dramatically increase the responsibilities of marketing or distribution operations for utility financial performance.
- Smart grid capabilities make possible new frontiers in DSM program portfolios, features, designs, and promotions, and facilitate pre-payment programs.
- Business systems departments will need to develop electrical engineering understanding, while field services personnel will need to learn new information technology skills.
- Resources will need to be reduced in some functions and increased in others.
- New applications and systems integration will be needed to help employees and functions maximize the value of smart grid data.
- Organizational realignments, operating process changes, and incentive modifications will be required to maximize the value of smart grid capabilities.
- Regulatory administration will need to identify and pursue the rule and incentive modifications necessary to enable and encourage maximization of smart grid benefits.

A comprehensive and formal change management plan should be part of every utility's post-deployment optimization strategy and include organizational, operational, systems, capabilities, and customer program enhancement components *(see Figure 4)*.

Regulators are currently pre-occupied with a great number of critical issues, namely FERC transmission orders, new and proposed EPA regulations, and associated jurisdictional issues. IOUs face their own challenges, including flat or declining usage, capital constraints, and regulatory uncertainty. However utility customers will be served well if both parties focus some of their resources on maximizing the value of smart grid benefits through regulatory and operational changes. This focus likely will be rewarded with both improved smart grid economics and enhanced services for customers. F

Endnotes:

1. The results of independent evaluations of two smart grid deployments led by the author for MetaVu Inc. are available on Colorado and Ohio PUC websites.
2. Ahmad Faruqui and Sergici, Sanem, "Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment," *Journal of Regulatory Economics*, 2011, vol. 40, issue 1, pp. 82-109.
3. SAIDI = system average interruption duration index; SAIFI = system average interruption frequency index; MAIFI = momentary average interruption frequency index.
4. Illinois Public Act 097-0616
5. EPRI, report #1020342.