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Protecting Customers from Utility Information System and Technology (IS/IT) Failures

How performance-based regulation can mimic the competitive market

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Introduction

Advanced information systems (IS) and information technology (IT), including benefits of automation, offer the same enhancements in service and efficiency to the utility sector as they do to other sectors of the U.S. economy. Almost every technological advancement has IT and IS behind it to make it work. Consider the example of smart meters: They require software to function; communications systems both to perform data collection and to connect their own software and hardware with the utility's systems; and, most importantly, data retention systems that allow access and analysis, as well as sharing or use of data by customers, the utility, and energy service providers. When a distribution component fails, the utility can now pinpoint the component, isolate it, and either have the system fix it automatically or otherwise figure out how to fix it, all within a fraction of a second. To make these systems work, it is critical that each set of IS/IT systems work well itself, be synchronized to interface with other systems, and have the capability to hold, store, analyze and maintain data in usable form. For smart meters, these systems can allow access to data in near real time (to assess grid conditions) or monthly (for billing).

Take the smart meter example and multiply it by six or eight and you have the magnitude of advanced systems many utilities are implementing today. What are the chances they will all come in on budget and on time and work as they are expected to? Whatever one answers to that question, the chances improve substantially if utility management knows they will be held to account for

[1] The authors acknowledge and thank Chris Villarreal of Plugged In Strategies for external peer review and Rick Weston and Camille Kadoch of RAP for internal peer review of this paper.

losing revenue if the systems do not work, or are late and over budget – as would occur to a company in a competitive market.

These technologies promise better and faster information to utilities and customers, better and more reliable service, and greater visibility into the operations of utility grids. Developers of energy services and systems release new grid and customer technologies, new products, and new services every day. These new technologies are coming to market in an era of increased energy innovation, distributed energy resource (DER) deployment, growing customer desire to control and make choices about their energy use, and a need for better outage management and enhanced resilience. Utilities see a need to manage advanced meters, sensing devices, and controls on the grid.

SUNDAY, JUNE 23, 2019

In Maine/N.E. Motorcyclists mourn the deaths of seven killed in N.H. crash / B1

Maine Sunday Telegram

★★★ $2.80 / $3.30 outside Cumberland, Sagadahoc, York, Knox and Lincoln counties

EST. 1862

SPECIAL REPORT

ELECTRIC SHOCK

How Central Maine Power misled the public and mismanaged the rollout of its new billing system

A Portland Press Herald/Maine Sunday Telegram investigation reveals that layers of the electric utility's management misjudged the enormity of the changeover, leaving thousands of angry and frustrated customers.

By TUX TURKEL
Staff Writer

Last October, nearly 1,000 utility industry professionals from 100 companies descended on the Grand Hyatt hotel in San Antonio, Texas, for a three-day software conference.

Donna McNally, a veteran information technology director for Central Maine Power Co., was there to tout her company's new customer billing system. In a presentation, she told the audience how CMP's new software, launched exactly one year earlier, increased billing accuracy and "enhanced customer experience."

What she didn't tell them was that 2,000 miles away, back home in Maine, more than 100,000 customers had been receiving inaccurate and, for many, outrageously expensive power bills. Or that many residential and commercial electric customers never received any bills at all — until they were caught off guard and alarmed by shutoff notices. Or that CMP was now the target of multiple state investigations, plus a ratepayer lawsuit alleging corporate fraud over how the company mismanaged the bungled billing system.

The Texas presentation was not the first time, nor would it be the last, that CMP management misrepresented the customer service disaster that shattered the reputation of Maine's largest utility. In late March of this year, CMP's chief executive told the Maine Public Utilities Commission that the billing problems were largely solved. But even now, customers continue to complain to the agency about unexplained high bills and their ongoing frustration with trying to get answers from CMP.

A Portland Press Herald/Maine Sunday Telegram investigation has found that officials at Central Maine Power and its parent company cut corners, skirted best industry practices and failed to adequately test a new error-prone billing system launched in the fall of 2017.

The meltdown of the new $56 million billing system, paradoxically named SmartCare, reveals a pattern of corporate mismanagement and unfulfilled customer promises spanning much of this decade.

Gregory Rec/Staff Photographer

Michael Harvey, who has received monthly electric bills as high as $1,400 for his 1,100-square-foot Winthrop home, checks upcoming dates for regulatory hearings related to the bungled rollout of CMP's new billing system.

The newspaper's examination of documents, testimony, emails and interviews reveals:

■ Managers skipped critical tests and rushed through others that would have alerted officials that the system was not ready to launch.

■ The origins of the fiasco date back to 2010, when the company installed a taxpayer- and ratepayer-financed smart meter system that promised customer savings. But nine years later, the most significant savings have only benefited the company after it laid off 85 meter readers.

■ A poorly timed corporate employee buyout and reduction of customer service positions left CMP understaffed at crucial times.

Please see CMP, Page A10

Dan McCanna/Staff Photographer

The Dixons in Waterville – clockwise from top left, Shanon, Aaron, Joslin, Sera and Keira – say they resorted to drastic measures – less flushing, showers at the local Boys & Girls Club – when CMP bills grew cost-prohibitive.

■ FRUSTRATED CUSTOMERS ON THE FRONT LINES

More than 100,000 customers – like the Dixons, at left – have become embroiled in Central Maine Power's billing system fiasco, some of them resorting to desperate measures to cope with inexplicably high bills. We've compiled a dozen of their troubling stories inside. Pages A9-A13

■ 'UNFULFILLED PROMISES' OF THE SMART METER UPGRADE

Learn why a shift to real-time pricing for home customers – and $338 million in potential savings – never materialized. Page A10

■ WHAT SHOULD YOU DO IF YOU HAVE BILLING DISPUTES?

Twenty months after CMP mismanaged the switch to its new billing system, here's what you need to know if you've been affected. Page A11

You can also read it all at www.pressherald.com

Smart meters, grid sensors, supervisory control and data acquisition (SCADA), and geographic information systems (GIS) all generate exponentially more data than utilities managed just a few years ago. These data contain both customer information and system information — a distinction that was meaningful in years past but may not be so distinct any longer. Sensors, meters, wireless capability, GIS, and data management systems give utilities, customers, and third parties access to new capabilities and functionalities and promise even more. Yet, deployment of these technologies carries a distinct set of risks and potential benefits for ratepayers. The systems can enhance efficiency, operations, and customer service — or they can fail, requiring increased customer expenditure to sort out the reasons for the failure and attempt to fix it. Worse yet, customer service can suffer and impact customers in huge ways if the utility messes up its operations.

Utilities with technology implementation issue span the U.S. from California to Maine, Washington to Massachusetts. The Los Angeles Times summarized the L.A. Department of Water and Power's experience succinctly:

> *The Los Angeles Department of Water and Power's reputation hit a low six years ago when the agency's new billing system sent out wildly inaccurate bills, overcharging hundreds of thousands of customers.*
>
> *The chaos prompted widespread outrage and promises by the DWP to*

fix the problems and reimburse ratepayers $67 million in overcharges.[2]

Similarly to Los Angeles customers, Seattle City Light customers experienced "shockingly" large bills and 74,000 customer complaints due to multiple factors including a new $85 million computer system and how it interacted with advanced meters.[3]

In fact, utility companies do not seem to be able to get it right even the second time. The Scottish Power implementation of an SAP system was so poor – customers did not receive bills, received incorrect bills, and were charged late payments – that the CEO apologized:

> *We are sorry about this. It is our fault and that is why we have committed that no customer will be left out of pocket from our mistakes.*[4]

Scottish Power is owned by Iberdrola which also owned Central Maine Power, leading to instructions not to let the Scottish Power implementation problems happen again with CMP – but they did. Were these utilities in a competitive market and overbilled customers due to bad computer and billing system implementation, they would lose customers and revenue to competitors that did IT/IS system implementation seamlessly.

Under standard cost-of-service regulation, the risk of IS and IT development, design, contracting, and implementation costs — as well as the costs of delays, suboptimal performance, and lost utility efficiency — is often borne by the ratepayers. In contrast, in a competitive business environment, the risk of whether a system is

SIDEBAR

Impact on CMP Customers:

> *"Affected CMP customers resort to defiant, desperate measures to cope [with incorrect bills]. Some tried to save money by camping outside, cooking on a propane burner or showering with a garden hose. Others tried selling their homes but found no takers because of the exorbitant electric bills. . . When these Central Maine Power customers complained that the invoices were wrong, the company provided a litany of excuses: someone was stealing their electricity, faulty appliances were sucking up more power, or their children were playing too many computer games. More than 100,000 residential and commercial customers – and likely many more – were victims of the power company's billing system fiasco."*

Maine Sunday Telegram, June 23, 2019, page A9.

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2 *Los Angeles Times,* "Six years after overcharging fiasco, DWP's lawyer accused of double-dealing," March 16, 2019, on the web at https://www.latimes.com/local/lanow/la-me-ln-paradis-dwp-lawsuit-20190313-story.html.

3 *The Seattle Times,* "Seattle auditor to investigate City Light practices after complaints over huge electricity bills," Sept. 11, 2018.

4 *Maine Sunday Telegram*, "Electric Shock: CMP's Botched Billing," quoting Neil Clitheroe, Scott Power's CEO in a public statement.

made operational on time and on budget and delivers the desired functionality is borne by the company and its owners or shareholders. If a regulated utility system is over budget, that cost is usually wrapped into rates — unless the regulator finds that the company was imprudent. An imprudence finding is a strong regulatory tool, but it is rarely applied in practice. Such imprudence findings often require focused examination by the regulator and are strongly opposed by any utility, thus absorbing substantial regulatory resources.

Key Concern: Timeliness, Cost Overruns, and Performance of Advanced IT/IS Systems

Regulators have not traditionally focused on thinking about whether advanced technologies will deliver promised benefits, but they need to learn to do this effectively. It does not necessarily mean getting into the technical weeds of a new IT or IS system, rather, it requires clearly laying out the functionalities to be achieved for customers and the utility on a specific schedule and budget. Regulators can then clearly weigh the benefits of those functionalities against the costs and risk for customers.

If utility management fails to deliver a system or fails to manage a contractor in delivering those expected functionalities, in theory a regulator can open a prudence proceeding. But as mentioned, such proceedings are resource-intensive and involve a lot of post-hoc judgment and perhaps second-guessing. Utilities can challenge imprudence findings in court taking even more regulator resources. And regulators are often reluctant to find imprudence even with a clear record of cost increases and substantial implementation delays[5] – leaving ratepayers footing the bill. There is a better way: performance-based regulation (PBR) which can mimic competitive forces and shift some of the risks of failure to the utility. In short, regulators can create a set of positive and negative incentives attached to the promised functionalities, schedule, and budget.

A PBR framework can replicate the competitive business environment: if a project is done on time and on budget, the utility receives higher revenues. On the other hand, if it is done late or over budget, the utility receives lower revenues. If some promised functionalities do not work at all, the utility receives even lower revenues. PBR applied to these investments can shift some of the risk to management and company shareholders and thus motivate utilities to deliver functionalities on time and on budget. If the system works well, for example by reducing peak through load shifting more than anticipated there should be room for higher utility earnings.

This white paper discusses some of the key foundational questions to which regulators should seek

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[5] The Massachusetts Department of Public Utilities (DPU) for example declined to judge an IS/IT project that clearly was over original budget and clearly had extensive implementation problems under prudence review from the cost increases and implementation issues but rather looked at what the company knew at the time is decided to go forward: "Regarding increases in project costs, a prudence review of a company's actions is not dependent upon whether budget estimates later prove to be accurate, but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. D.P.U. 93-60, at 35; D.P.U. 85-270, at 23-24." MA DPU, 15-155, page. 302, Sept. 30, 2016.

answers when considering a PBR approach for IT/IS investments. Then the paper describes some of the technologies in question and how they function on an electric distribution system, as well as considers the applicability of PBR to these investments.

Foundational Questions for Regulators

There are key questions that can help regulators identify the key goals, parameters, milestones, and costs that determine whether an investment in IT/IS technology is likely to be in the best interest of ratepayers, and why, and then guide regulators in ensuring those benefits are secured.

1. What *functionalities* are utilities saying the technology in question can deliver? Utilities should be able to describe in a simple way what the technology will enable them to do and, thus, the benefit for customers and the utility. Regulators need to identify promised benefits and weigh those against the costs and risks (if any) for ratepayers. A deployment schedule focused on customers may include milestones for threshold numbers of customers to obtain and share their information with third-parties – in other words focus metrics on functionalities actually achieved with and for customers.

2. What is the *deployment schedule* utilities say they will meet and what are the *costs, both capital and operation (CAPEX and OPEX)*? Does the schedule get laid out to refer only to installation, or availability of the function or actual use of the functionality by customers? What are the CAPEX expenditures by year or quarter and what will be the OPEX? It is probable that the implementation of some new IT/IS systems will be delayed, so regulators should ask: Who absorbs the cost and impact of project delays? Who assumes the risk of project delays and loss of functionality, failures to perform, potential project failure, and cost overruns? What risks fall on the ratepayers, on the utility, and on the utility contractors? What risk/cost arrangements can maximize the chances for timely and cost-effective implementation?

3. How will various *technologies interact/interface*, and do certain functionalities need to be deployed before others for the overall system to work effectively and interoperably? What is the full technology suite, the full cost, and the interrelationship of the IS and IT functionalities? Do the systems need to be sequenced and are any of the systems vulnerable to delays, interruption, or failure? How is interoperability achieved, maintained, and enhanced?

   Modern meter or sensor systems require software and hardware themselves; they also require communications equipment and often hardware and software for the communications equipment to transmit data into a receiving system that might in turn categorize, analyze, and store the data in a database. Some utilities are calling these new massive databases "Data Lakes." That database can be accessed by other systems, and information might be shared through a firewall to a system outside the utility firewall to make the data available to a customer and/or third-parties. In describing how a meter

SIDEBAR

"Smart meters' promised savings never came"

"The promise was that smart meters would give home customers real-time information on electricity costs, so they could shift power to use when it's less expensive.

. . .

But what few people understood at the time was that the potential couldn't be realized until CMP upgraded its vintage billing system. Additionally, CMP only delivers the power to 620,000 Mainers' homes. The companies that generate electricity also had to buy-in to real-time pricing.

CMP's upgrade was deferred and delayed for years. When SmartCare, the new billing system, was finally launched in 2017, it was plagued with problems and complaints that are still being resolved.

Maine Sunday Telegram, June 23, 2019, page 10.

system gets data ultimately to customers or non-utilities, we have identified six different functions for interacting and interfacing with an IT/IS system: 1) sensor/meters, 2) communications, 3) receiving/analyzing/formatting system, 4) database, 5) retrieving system for access, and 6) a public access system through a firewall. If any one component experiences a failure, the function fails. So, interfacing systems rely upon one another to accomplish specific functions.

A recent example where the interaction between technologies created a problem for customers is National Grid's IS/IT upgrade and modernization using an SAP Enterprise Resources Planning platform that encountered substantial cost increases and implementation issues. The problems were so significant the Massachusetts Attorney General asked that the company ROE be reduced to its long-term capital rate of 3.7% for those costs and $9 million in expenses be disallowed.[6] A second example is Central Maine Power's smart meter system. This system failed to deliver on anticipated and promised time-variant rate offering options because the data from the meters was not made available to third-party suppliers due to delays in updating the billing and data system.

[6] The Massachusetts regulator, the DPU, did not disallow those expenses nor reduce the rate of equity to 3.7%, but it did reduce the ROE from 10.5% to 9.9% to avoid National Grid's ratepayers from subsidizing the National Grid affiliate providing IT/IS service to the regulated utility. MA DPU, 15-155, page. 298-302, Sept. 30, 2016.

4. What is the *next-best system* and what is the cost of the next-best system? Goals, targets and metrics are ideally laid out so it is clear how regulators and the utility can assess cost, gain or loss of certain functionalities or the net value proposition for ratepayers. Is the next-best system more or less risky? Will ratepayers still see the benefits?

5. Does it make sense to *outsource the service to third-party providers* who have a track record of success? What are the relative costs and benefits during the test year and beyond of capital and operating expenses over the expected life of the system? How does outsourcing costs compare to building the system internal to the utility?

6. What are the *best management practices* for deployment and operation of the technology(ies)? Is the utility using contractors or vendors with a record of success implementing or operating these technologies? Can the regulator provide guidance that in turn encourages the utility to manage outside contractors effectively?

7. How can regulators *replicate the pressures that competitive firms face* when adopting new IS/IT systems, such as loss of customer trust, loss of customers, market share, and revenue, in the event that the utility mishandles the project?

Grid Modernization and Associated Technologies

Utilities, like all sectors of the global economy, are taking advantage of advances in information technologies, software and services to more effectively and efficiently provide safe and reliable service to their customers. Advances in metering, measurement, and sensing technologies and the ability to monitor, communicate and coordinate management of distribution, transmission and generation with demand-side technologies are changing the face, functions, and operational models of the utility sector. The energy markets are changing whether the incumbents welcome this change or not.

A utility that is not planning for, designing, and implementing grid modernization two decades into the 21st century is imprudent. Tapping into the capabilities of advanced information technologies is part of operating any business today. Utilities and their customers will benefit from the cost-effective and well-managed adoption of advanced technologies. Achieving this requires a particular set of management skills. While a utility may be imprudent for failing to modernize its systems, it does not follow that adoption and implementation of these information technologies is per se prudent.

There are many ways that implementation of information technologies can result in delays, cost overruns, failure to achieve intended functionalities, or even overall failure of the project. Like any project, having competent, capable and experienced management of internal utility work and external contractors is critical to success. The question for regulators is, in this era of increasing IS/IT needs, how can regulators encourage utilities to do it effectively and replicate the same pressures that competitive firms face when adopting new IS/IT systems?

In the table below, we provide a summary of some common types of IT technologies that utilities wish to deploy. This list focuses on technologies to enable better operations and visibility of the distribution system. There are also a host of IT products focused on customer service, billing, and information, that may be good candidates for some of the basic PBR ideas discussed below. These are not included in this table due to the focus on distribution system and grid modernization in this memo.

Technology type	**Basic functionalities / purposes**
Advanced distribution management systems (ADMS)	Integrated operating and decision support system to assist control center operations, field personnel and engineers.
Field area network (FAN)	Communication network necessary for the implementation of most other grid modernization programs. May be needed for AMI to transmit information to and from the meter and can include backhaul and telecommunications management systems.
Fault location isolation and service restoration (FLISR)	Improves distribution system reliability by isolating a faulted segment of a feeder and automatically restoring power to un-faulted segments. Gives ability to see real time load across many critical points on the distribution system. Data from FLISR can be used to plan and design the future system. A core application within ADMS, with a longer deployment timeline.
Advanced Metering Infrastructure (AMI)	Customer level visibility. Set of technologies which encompasses smart meters, communications networks, and information systems to inform the utility at a basic level of customer and network behavior as it pertains to billing and performance. Can be linked with thermostats, smart appliances. Technologies that depend on AMI: ADMS, outage management programs, home area network, demand response management system (DRMS).
(Distribution) Supervisory Control and Data Acquisition (SCADA or DSCADA)	Provides observability on the system to better understand where outages have occurred. Typically, available at substation level but not on 100% of distribution circuits.
Distributed energy resource management system (DERMS)	Provides situational awareness, control/dispatch and monitoring of DERs on the distribution system, such as PV, storage, EVs, or demand-responsive load.

GIS-based operational and asset management systems	Tracks distribution lines, transformers, customers, substations and sometimes DER systems.
Volt-var optimization (VVO)	Flattens and lowers the distribution system voltage profile to reduce overall energy consumption. Increases the ability to host DER and do demand response. Uses data from end-of-line sensors to automatically control voltage regulators and load tap changers at the substation.
Data lakes	Large database for multiple applications. The raw data from various meters, sensors and operations are combined into analytical data models to be processed using advanced data processing and analytical techniques. Planners, designers and system operators should be able to access the data lake and its content for both enterprise and operational data purposes.
Telecommunications: wide area networks (WANs)	The WAN architecture being deployed at high-voltage substations and generation facilities has been engineered as a converged network solution (the coexistence of telephone, video and data communication within a single network).
Automatic transfer recloser (ATR)	ATRs enable distribution automation loops. Installed as sets on the system between two lower-voltage feeders, creating an automation loop. ATRs transfer load automatically in the event of an outage, reducing customer outages, and improving system reliability by isolating a faulted section of a feeder. The “loop scheme” software on these devices is designed to operate even when communications are down on the device.
Line regulators	Distribution line regulators are essentially a tap changing transformer utilized to increase or decrease voltage on the primary distribution system based on changing load conditions. The goal of the regulator controller replacement project is to enable two-way communication between the regulator controller and a DSCADA application.
Line/feeder sensors, fault indicators	Line sensors are an integral part of FLISR to detect faults, determining the faulted section and the probable location of a fault. Line sensors also provide information about feeder loading, fault current, momentary outages, permanent faults, line disturbances and high current alarms, and should reduce customer outage minutes.
Controllable field devices not included above	Advanced capacitors and station regulators, smart reclosers and breakers

Applicability of PBR to Protect Customers from IS/IT Failures Mimics Competitive Markets

Regulators should consider using PBR methods to better motivate utilities to accomplish two outcomes: delivering working IT and IS investments on budget and completing their deployment on time. These objectives are ripe for PBR application because under the status quo, utilities and their shareholders bear very little risk for the possibility that the investments (and their associated functionalities) could be delayed or over budget. Absent an imprudence determination by the regulator, ratepayers ultimately bear the downside risk of technology failures or errors in design, integration, training, software, development, or implementation. By attaching a performance metric to the budgets and timing of projects, some of the downside risk can appropriately be shifted to utility shareholders, while also providing an upside outcome should the project be delivered early or under budget.

A primary tool for implementing this is an adjustment to the utility return on equity for the investment in question. For example, if a company's IT deployment plan includes a deployment of a certain number of AMI meters by a certain date, a simple metric would require the company to report at some regular interval on how many meters have been deployed and are operational. Achievement of the goal in a timely fashion could result in a small adjustment upward in the return on the equity represented by investment in the meters and associated IS/IT systems. A delay in achievement of the goal could result in a downward adjustment, which regulators may or may not want to make more severe than the potential upside adjustment. A "dead band" approach could be used: For example, completion of the rollout during the three months before or after the target deployment date would result in no adjustment.

Defining "operational" is important and requires some thoughtful objective criteria to make sure the system is working properly and not simply declared operational. The budget and timeframes for each project are also important to ensure they are reasonable by industry standards and to meet the needs of the utility and ratepayers. French regulators in fact did just this for smart-grid roll-out for Électricité Réseau Distribution France (ERDF), one of the distribution system operators in France. Given the size of the ERDF project and the need to guard against increases in costs or forecasted completion times, a specific PBR frame was implemented that gives ERDF incentives to control investment costs, comply with the deployment timetable, and guarantee performance of the system installed. The French energy regulator will further ensure the pattern of operating charges presented by ERDF is consistent with projections both for cost reductions in meter reading, technical work and reduces line losses and for costs of the operating metering system mainly for the IS and system administration.[7]

7 Littell, D. Kadoch, K. Zinamen, O., Logan, J. et al. 2018. Next-Generation Performance-Based Regulation, Vol 3: Innovative Examples from Around the World. 21st Century Power Partnership, NREL, Clean Energy Ministerial and Regulatory Assistance Project, https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume3_april_2018.pdf, pp.

On the other hand, policy makers can actually make counter-productive incentive decisions such as in the State of Illinois. The Illinois legislators inadvertently slowed down Ameren's deployment of AMI because they lowered the percentage of operational AMI meters to meet a PBR metric under Illinois's regulatory scheme.[8]

To provide some further examples of how applicability of PBR to these IT/IS systems would work, here are some illustrative general approaches:

- If a system is operational on time and on budget, the rate of return (ROR) for that used and useful component is increased by 100 to 500 basis points in year one, reverting to ordinary ROR thereafter.
- If the system is over budget, the ROR is reduced by 10 basis points for each 1% the project is over budget for the life of the asset(s). Regulatory oversight or independent auditing may be necessary to ensure additional costs are not billed to other accounts.

SIDEBAR

French PBR for Smart Grid Deployment

"The French incentives for timely and on-budget deployment of its smart meter system involve basis points and incentives for the three components:

1. Control investment costs.
a. ERDF is penalized from the first euro of additional cost because it loses the bonus of 200 basis points on this additional cost. If the additional costs exceed 5%, no further costs are remunerated (i.e., no bonus and no base-rate remuneration).

b. From the first euro saved, ERDF keeps a bonus equal in amount to the bonus as it would have been with no saving. Grid users benefit from reduced capital charges (lower depreciation and base-rate remuneration).

2. Comply with the deployment timetable. This incentive focuses on the number of meters that are installed and able to communicate compared to the forecasted deployment timetable. Monitoring takes place regularly throughout deployment. If the forecasted deployment percentages are not achieved, penalties are generated. To ensure that complying with the deployment timetable does not jeopardize the quality of the installation, the Commission de regulation de l'energie has put in place a financial incentive relating to the percentage of return visits after a Linky meter is installed during the deployment. It will also monitor the percentage of complaints related to deployment.

3. Guarantee the performance level expected from the Linky metering system. The quality of service for the Linky metering system is a key element not only in improving the functioning of the electricity market but also in realizing benefits in terms of technical intervention (estimated at €1.0 billion [2014] at current value) and meter reading (estimated at €0.7 billion [2014] at current value). These benefits are directly proportional to the performance level of the metering system. Poor performance would thus have a significant impact on the economic value of the Linky project."

Littell, D. Kadoch, K. Zinamen, O., Logan, J. et al. 2018. Next-Generation Performance-Based Regulation, Vol 3: Innovative Examples from Around the World. 21st Century Power Partnership, NREL, Clean Energy Ministerial and Regulatory Assistance Project, https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume3_april_2018.pdf, pp. 29 and 30.

- If the system is under budget and fully operational, ROR is increased by 10 basis points for each 1% it is under budget for year one, reverting to ordinary ROR thereafter.

Why, one might ask, would regulators reward delivering an advanced system on budget and on time? The answer is that for advanced systems with contractors involved, the management focus necessary to ensure successful implementation, combined with the customer benefits of successful implementation (and avoided customer costs of failure), justify an added return. This is worth considering simply because the status quo is that ratepayers pay for suboptimal yet not imprudent utility work.

Potential gaming

As with the application of any regulation including performance-based system, there is the possibility that utilities will try to game the system rather than performing as expected by the regulator. Here, a utility could propose an unnecessarily long timeline for deployment, knowing that they would see a higher ROR if they deliver “early.” Similarly, a utility could propose an unnecessarily high budget, knowing that delivering under that figure could result in financial gain. There are ways that regulators can address gaming risk:

- If proposed expenditures are on capital, the utility would put those investments into their rate base under normal regulatory operations. The commission can make sure that the utility cannot put those investments into rate base until they are used and useful and deny carrying costs, giving the utility an incentive to meet a reasonable timeframe.
- One of the most useful ways to assess whether proposed costs are accurate is to compare the cost of implementing the same system in similar jurisdictions or peer utilities.[9]
- Ultimately, review of timelines and budgets will be an important undertaking for Commissions particularly when possible additional ROR adjustments depend on budgets and timeframes being reasonable.

[9] Utilities often present this information in testimony but often not from entirely public sources. For example:“In the latest UNITE Benchmark completed in July 2018, calendar year 2017 was evaluated as the study period. In infrastructure results, the Company ranked on top or mid-range in unit costs in 11 out of 16 service areas evaluated when compared to other utilities within its peer group. Peer groups are defined by UNITE by taking into account factors such as capacity and complexity for comparison purposes. In infrastructure performance metrics, the Company achieved top rankings within its peer groups for 11 of 13 service areas evaluated. When considering total IT spend for infrastructure, applications, and support functions, the Company’s IT spend was in-line with UNITE median spend, on both a percentage of revenue and per customer basis.” Consumers Energy Testimony by Christopher Varvatos Presented in Michigan Public Service Commission Case No. U-20322 (Nov. 2018), page 14, lines 8-14. Publicly available information on costs across jurisdictions is most helpful whereas proprietary “expert” information often cannot be validated and is therefore less reliable and sometimes easier to manipulate.

Advanced Use of PBR to Mimic the Competitive Marketplace: Better Service Raises Revenue and Poor Service Results in Losses

The basic PBR approach above focuses on achieving an advanced system that is operational on-time and on-budget. "Operational" means having successfully implemented a series of tests and a period of full operations (this could be a month, quarter or year).

The definition of "operational" can also focus, if regulators think it appropriate, on specific functionalities to be achieved. This requires developing descriptions of what functionalities a system is supposed to deliver to ratepayers, the utility and the public at large.

Ideally, these functionalities are objective and verifiable. The table below demonstrates potential goals and outcomes associated with AMI deployment, and associated performance criteria and metrics that could be used to track whether the utility is successful at achieving the stated goal. AMI together with associated IS/IT systems and expected customer uses involves a variety of functionalities related to specific outcomes that could, if sufficiently valuable, be associated with a ROR added for a single year or for the entire life of the system(s).

Goal	**Outcome**	**Performance criteria/Functionality**	**Metrics to track**
Personnel savings	More efficient and less costly metering	AMI system provides reliable and regular metering information to utility billing system	Accuracy of customer bills and customer complaints on billing
Accurate and timely customer billing	Timely and accurate customer bills	AMI, database and billing system provides timely and accurate bill to customers	Timely information to the utility-the meters are tested to 98% or higher accuracy; or reductions in estimated bills
Improved storm response	Timelier storm response	Utility Outage manage system receives outage information	# of meters successfully providing accurate outage information for real time storm restoration
Customer understanding of energy usage	Higher customer satisfaction or understanding of energy usage	Operation of customer energy usage portal	Customer usage of energy portal, one time or regular access

Vibrant real time or TOU energy market for residential users	Customer costs more reflective of system costs: efficient pricing	Customers on a real-time or Time-of-Use (TOU) rate plan	# and % of customers adopting out of or taking real time or TOU price offering
Third-party energy provider authorized access to customer data	Utility system supports works system for customers to share data with third-parties	Third party energy service company ability to access Green Button Connect data	Number of third parties successfully accessing customer data through Green Button Connect or other utility data sharing method; customers are able to authorize of third-party service company requests on first attempt (target 95%); third-party service provider receive access when authorized by customers (target 95% of the time)
Customers use of automated storm outage information	Higher customer knowledge of outage situation and storm response	# or percent of customers using storm outage system each day during storm events	# such as 10,000 customers using storm outage information for their accounts

The metrics in this table are described conceptually but not precisely. In practice, the precise metric and data it relies on should be specified in another column with precision. For example, for third-party access facilitation metrics it could measure: customer authorizations of third-party data access (target 1,000 per month) within one year of system operation, customers are able to authorize of third-party service company requests on first attempt (target 95%), and third-party service provider receive access when authorized by customers (target 95% of the time).

And if PBR is put in place beyond tracking metrics, the ROR adder, cash payment to go to shareholders, or range of incentives can be described in another column. That is exactly what PBR looks like, desired goals and outcomes lead to performance criteria to precise metrics, possibly with incentives attached to reflect superior and inferior performance.[10] A dashboard depicting results of performance metrics can make transparent the expectations regulators are setting for utility performance in specific areas.

[10] In fact, the U.K.'s PBR initiative known as RIIO for Revenue=Incentives+Innovation+Outputs has produced significant tables that look like the expanded version of this table further developed along lines suggested in these paragraphs. For information on the U.K. RIIO initiative, see the U.K. Office of Gas and Electricity Market, RIIO website: https://www.ofgem.gov.uk/network-regulation-riio-model.

Conclusion

Grid modernization is indeed an imperative for the utility industry. It comes with new costs and new risks for utilities, ratepayers, customers, and the public. If done well, all four will benefit. If poorly done by utilities who expect ratepayers to cover losses and fixes, the ratepayers, customers, and public will certainly suffer. The utility risks some disallowances for imprudence but even if an imprudence finding is made, the utility is likely to continue to make a positive ROE and ROR on the investment, just a slightly lower return. PBR is a way to fix that situation so utilities have an incentive to do it right, make higher returns if they do, and lose revenues if they fail. Utility grid modernization plans are increasingly expansive and propose to add billions of dollars into utility ratebase. Those proposals are ripe for PBR consideration.

Energy Solutions for a Changing World

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