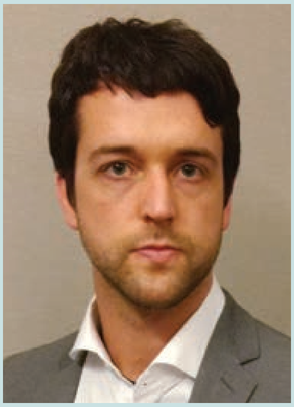
Rush to Modernize

An Editorial on Distribution Planning and Performance Measurement

By Paul Alvarez, Sean Ericson, and Dennis Stephens



Legislators and regulators in some states appear increasingly obsessed with grid modernization. Legislators are ordering regulators to provide incremental economic incentives for extraordinary/modern grid investments.

Regulators are busy evaluating large grid investment proposals from utilities or establishing requirements for grid investment proposals that are outside the routine course of business. Some regulators are even overseeing the creation of new distribution planning processes involving stakeholders, similar in nature and features to Integrated Resource Planning as demonstrated by Alvarez in a November 2014 *PUF* article.

But regulators have little access to technical experts with objective perspectives. As leading evaluators of grid modernization plans for consumer, business, and environmental advocates, and with extensive experience in IOU distribution grid planning and operations, the authors share their perspectives on distribution planning in this editorial.

What's Driving the Interest in Grid Modernization?

Given the apple pie goals of grid modernization, it is difficult for anyone – legislators, regulators, or customers – to oppose it. The authors do not dispute the attraction, and recognize grid modernization potential commonly cited by utilities, suppliers, and government agencies as legitimate, including: Improvements in reliability and resilience; Reductions in operating costs, energy use and coincident system peaks; Reliable accommodation of increased distributed generation (DG) capacity; Preparation for increased load from beneficial electrification (including electric vehicles); and Reductions in environmental impact associated with the above.

Some utilities also cite job creation as a goal, though employment increases from grid development must be evaluated in the context of community-wide economic impacts from higher electric rates. In grid modernization, as in most complex endeavors, the devil is in the details. Grid modernization is not a bargain at any price, nor is it a no brainer, though it can deliver benefits to customers and communities in excess of costs with sound distribution planning and performance measurement.

To get good results for customers, modern grid investments must be carefully managed, in both planning and monitoring contexts. Investment incentives motivate utilities to grow earnings by spending capital on their distribution grids. As the need for new generation is low to non-existent, and the average lead-time for new transmission now exceeds ten years, distribution grid investment has become the most attractive regulated investment option.

While the goals of grid modernization are sound, and the potential benefits are real, the incentive to invest more than necessary to accomplish the goals is also real and can be addressed through distribution planning. Many types of benefits reduce electric sales volumes, so post-investment monitoring is critical too. Distribution planning and performance measurement processes can be structured to address these issues and maximize bang for the buck for electric customers.

Paul Alvarez leads the Wired Group, a consulting practice dedicated to unleashing latent value in distribution utility businesses. **Dennis Stephens** EE is a Senior Technical Consultant at the Wired Group specializing in grid planning, operations, and investment. **Sean Ericson** is a Wired Group Associate and PhD candidate at the University of Colorado who specializes in energy industry econometric analyses.

Distribution planning, by providing an evaluation framework for grid investments, can, and should, be perceived as a cost recovery risk reduction tool.

Separating Grid Mod Fact from Fiction

When developing distribution planning processes, separating grid modernization fact from fiction can be helpful. Based on the dozens of grid modernization plans the authors have reviewed, misperceptions are common and can lead to sub-optimal distribution planning processes if maintained.

Fiction: Transparent and participatory distribution planning processes are unnecessary, as regulators retain the authority to deny cost recovery of imprudent investments.

In reality, regulators are highly unlikely and perhaps even unable to deny grid modernization cost recovery, for two reasons. First, grid modernization proposals are generally so large that rejection of even a small portion of investment can impact utilities' ability to secure low-cost financing.

Almost all regulators recognize low-cost financing as an important objective; in a few states, this is required of regulators by law. Second, the bar for imprudence is high. Almost any grid investment a utility can make is used and useful to some extent, making an imprudence finding extremely difficult to secure. In practice, cost recovery denial is a hollow threat for large grid investments.

Though the risk of cost recovery denial for modern grid investments is low, this does not prevent IOUs from claiming otherwise in their requests for incentives beyond authorized rates of return on such investments. Indeed, cost recovery risk is first among the arguments IOUs cite when claiming that preferred cost recovery is a prerequisite for modern grid investments. Distribution planning, by providing an evaluation framework for grid investments, can, and should, be perceived as a cost recovery risk reduction tool.

Legislators and regulators are encouraged to consider the possibility that distribution planning is the best way to reduce cost recovery risk, as well as the possibility that preferred cost recovery methods are not required to stimulate grid investment. As the most attractive regulated investment option remaining, IOUs are likely to spend capital on the grid without preferred cost recovery.

Fiction: Modern grid investments are similar in a prudence context to generation, transmission, and traditional distribution investments.

In fact, nothing could be further from the truth. Generation, transmission, and traditional distribution investment prudence is very black and white. G, T, and D capacity is either needed or it's not; once the investments have been made, new G, T, and D capacity is either available to serve customers or it isn't.

In contrast, modern grid investments are distinctly grey in character. As existing distribution grids are already reliable, reasonably efficient, and friendly to inverter-based DG to a significant degree (more on that below), the need to make huge modernizing investments is not black or white but lies on a continuum. Prioritizing needs, and the most cost-effective ways to address them, are at the heart of sound distribution planning processes.

Fiction: Benefits from modern grid investments are certain and require no monitoring or performance measurement.

Like prudence, the level of benefits delivered from grid modernization is neither black nor white but varies widely from utility to utility. Consider smart meters or conservation voltage reduction, in which the level of benefit delivered is either totally controlled by, or heavily influenced by, utility choices in marketing, operations, rate case timing, data utilization and access, systems integration, change management, organizational development, and other domains.

Grid modernization investments are therefore distinctly different from traditional investments in both prudency and benefit variation, implying a need for new types of distribution planning and performance oversight by regulators.

Fiction: Modern grid investments are different and should be considered outside a defined distribution planning process.

While modern grid investments are different from traditional grid investments in terms of prudence and benefit variation, the idea that modern grid investments should be excluded from distribution planning processes does not follow.

Note that the goals of grid modernization listed in the introduction are the same as the goals most stakeholders maintain for the distribution grid in general. As modern grid components are simply a subset of the broader distribution grid, the need to exclude large grid modernization proposals from distribution planning processes is not supported.

The reality is that utilities already have good processes for evaluating potential distribution projects. Moreover, utilities have been adapting these processes for new grid operating issues and technologies as they've arisen for over a hundred years now. The fact that some new technologies are now on the customer side of the meter and may require some new technologies on the utility side of the meter, is somewhat beside the point.

Rather than using a different planning process for extraordinary grid investments/modern grid capabilities, or exempting them from planning processes altogether, existing processes should be adapted to address new grid operating issues. The adapted processes can then be used to evaluate each potential grid project, traditional or modern, based on each project's quantifiable contribution to goals relative to costs.

Like prudence, the level of benefits delivered from grid modernization is neither black nor white but varies widely from utility to utility.

This will significantly reduce the risks of over-investment and sub-optimal project prioritization and will be addressed in the Distribution Planning Process Features section later. In the authors' experience, distinguishing and evaluating some types of grid investments differently than others is related more to preferred cost recovery administration than to any misperceived deficiency in distribution planning capabilities.

Fiction: Rapid expansion of photovoltaic solar panel capacity demands immediate and pervasive grid investments.

While the Flexible Grid concept promoted by the Department of Energy and other groups can indeed increase distributed generation hosting capacity, and improve grid reliability and resilience to boot, it can be geographically expanded over time as a need to do so is demonstrated through risk-informed decision support (described later). In the authors' experience, rooftop solar installations do not complicate grid operations until high levels of capacity relative to load are observed.

While grid planners and operators in Hawaii and California have a greater sense of urgency, most grid planners can deploy the Flexible Grid concept on a gradual basis as distributed generation capacity growth warrants. Getting started with some distribution management system software and using it to operate a limited number of circuits, is a reasonable approach to gaining experience with the Flexible Grid and preparing for the future.

Fiction: Inverter-based distributed generation confuses protective devices, requiring wholesale protective device replacements or upgrades. Utilities often cite the need to change out large volumes of grid protection equipment as part of grid modernization plans. Utilities claim that distributed generation confuses circuit breakers, fuses, and similar devices, causing them to remain closed when they should open.

Circuit breakers and fuses that remain closed when they should open do indeed represent safety and equipment damage risks. However, only synchronous generation – that is, generation which creates electricity through a spinning turbine – confuses protective equipment.

Research indicates that inverter-based distributed generation, such as PV solar panels and batteries, disconnects from the grid instantaneously upon encountering a disturbance, at reaction times well within circuit breaker operating parameters.

Inverter-based DG thereby presents no need for protective device change-outs. This is not to suggest that there aren't some things utilities can do to begin preparing today for high volumes of DG capacity expected in the future, only that costly protective device change-out is not one of them.

Distribution Planning Process Features

Which modern grid investments deliver the biggest bang for the buck? The answers vary widely by utility and community and depend on both the grid capabilities already in place and stakeholder priorities.

But a transparent and participatory distribution planning process, combined with performance measurement, can improve project prioritization and selection, moderate capital requirements, and maximize customer benefits regardless of capabilities or priorities. When designing a recurring distribution planning process, regulators and stakeholders are encouraged to consider multiple characteristics, features, and perspectives.

Risk-informed Decision Support (Project Evaluation, Prioritization, and Selection):

Businesses competing in unprotected markets are capital constrained, and forever striving to maximize throughput (products, services, revenues) for the least amount of input, such as capital. The software giants serving businesses' accounting needs, like SAP and Oracle, have long recognized their clients' interests in conserving capital. A whole class of sophisticated software has therefore been available for decades to help businesses evaluate and prioritize capital spending based on risk reduction value.

To illustrate, consider a plant manager for General Motors. He or she maintains a portfolio of unfunded capital projects he or she wishes to complete at all times. Facing capital constraints, the manager must decide whether capital is better spent replacing the roof or upgrading the vehicle painting booths, for example.

The best choice comes down to the risk and consequences of failing to fund one or the other. The plant manager must balance the risk and cost of production interruptions from a leaking roof against the risk and cost in lost production time or re-work of sticking with existing paint booths. The relative size (in capital) of each potential project and the total size of the capital budget available to the plant manager, as well as risks and projects at sister plants, also come into play.

Risk-informed decision support software is designed to help businesses make difficult decisions by scoring, and then ranking, each project in a portfolio of potential capital investments based on benefits (risk reduction x event consequence) and cost. Scoring involves estimating the reduction in likelihood of an adverse event, as well as the size of consequences associated with specific adverse events, for each potential project.

In the electric distribution business, adverse events could relate to safety, reliability, resilience, cybersecurity, or distributed generation interconnection delays, while the consequences could be estimated in financial impacts to customers or communities associated with each. Regulators are strongly encouraged to require risk-informed decision support for project evaluation, prioritization, and selection in distribution planning processes.

Transparency and stakeholder participation should be a feature of distribution planning processes.

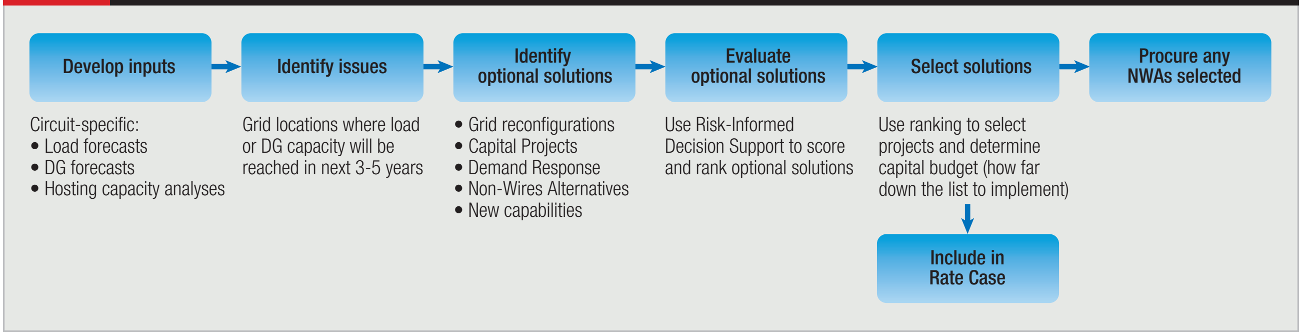
As part of such a requirement, regulators should also consider the appropriate role for stakeholders and their inputs into scoring, weighting, and line-drawing such as selecting projects and determining the most appropriate budget size.

Guidelines for customer benefit-cost analyses should also be addressed in distribution planning processes. For example, discounted cash flow analysis should be used to value far-off benefits in present day dollars. Costs should be estimated in terms relevant to customers, which is to say costs should include the carrying charges (profits, taxes, interest, etc.) customers will be asked to pay. Other questions to be answered include the most appropriate discount rate to use (utility, or customer?), as well as the manner in which the costs of assets retired prematurely to make way for modern counterparts will be treated, both in benefit-cost analyses and in cost recovery.

Transparency and Stakeholder Participation:

Transparency and stakeholder participation should be a feature of distribution planning processes. Not only do these features encourage rigor and intellectual honesty, they demand thoughtful consideration and negotiations among stakeholders about community priorities, the prices customers will pay to satisfy them, and the trade-offs which must be made given limited

Fig. 1 Suggested Least Cost Distribution Planning Process



interest in rate increases.

Transparency and participation have been features of integrated resource planning for some time, and their merits have been demonstrated. There is therefore good reason to apply these features to distribution planning.

On the other hand, micromanagement must be avoided. While stakeholders should be prepared to dedicate more resources to grid planning and performance measurement on an ongoing basis, there is no reason to involve stakeholders in every hundred-thousand-dollar decision in a billion-dollar capital budget. Instead, stakeholders should have a say in determining project scoring criteria, weighting, and selection, with a clear understanding of the risks which will not be mitigated for those utility-recommended projects which fail to make the cut.

Similarly, a regulator might choose to involve stakeholders in grid design standards and engineering models – not because the stakeholders are experts, but because they can then be exempted from having to review any utility decisions in compliance with approved standards and models.

A distribution planning process which features transparency and stakeholder participation changes utilities' roles. Historically, utilities made proposals and stakeholders reacted. With transparency and participation, utilities serve a more consultative and educative role in distribution planning, offering pros and cons of various approaches to achieving stakeholder priorities.

While utilities may prefer the familiarity of the historical approach, they should also consider the potential benefit of a consultative role. The authors believe that a transparent and participatory grid planning process reduces utility risk given the uncertain future state of electricity distribution. In the long run, a utility which dictates the grid a community gets is at greater risk for stranded costs than a utility which simply addresses the priorities established by stakeholders through investment plans the stakeholders helped create.

Periodicity and Timing:

Like integrated resource planning, distribution planning is an ongoing effort which should be updated periodically. The frequency and timing of distribution plan updates should be governed by community-specific dynamics, rate-case rules, and other factors.

Regulators should specify that grid investment performance will be monitored and measured as part of the distribution planning process.

As distribution planning is resource intensive for all parties, annual plans are not recommended. On the other hand, planning should not be so infrequent as to miss major developments; therefore, frequency less often than once every five years is not recommended either.

A community experiencing rapid growth in rooftop PV solar capacity may require more frequent planning cycles than a community without such growth. A state utilizing forward test years may wish to require grid planning processes in advance of rate cases, while a state with mandated rate case frequency, such as every three or five years, may wish to mirror that frequency in distribution planning. The point is to establish and enforce distribution planning expectations in a way that makes sense for local conditions, characteristics, and norms.

Distribution Planning Components:

Distribution planning components receive the most attention in most process development proceedings, and so will not be addressed in detail in this article. Suffice it to say that traditional components of grid planning should remain, augmented by new components dictated by community and stakeholder priorities.

Load forecasts by circuit have long been part of grid capacity planning and should remain, though load forecasts incorporating beneficial electrification, including electric vehicles, will be of particular interest to some stakeholders. Distributed generation forecasts by circuit will become an increasingly critical and routine component of distribution planning, as will a related component, the distributed generation hosting capacity analysis.

Upon consideration of these inputs a utility will identify locations on the grid where load or distributed generation capacity limitations are likeliest to arise in the next three to five years. The utility could then develop and propose a list of options to relieve the limitations, from grid reconfigurations and capital projects to new capabilities and non-wires alternatives.

Utilities will also develop optional solutions to mandates, from new customer connections to regulatory compliance. Options can then be evaluated using risk-informed decision support.

A list of projects recommended for funding should result, though some stakeholders will be interested in still more planning components.

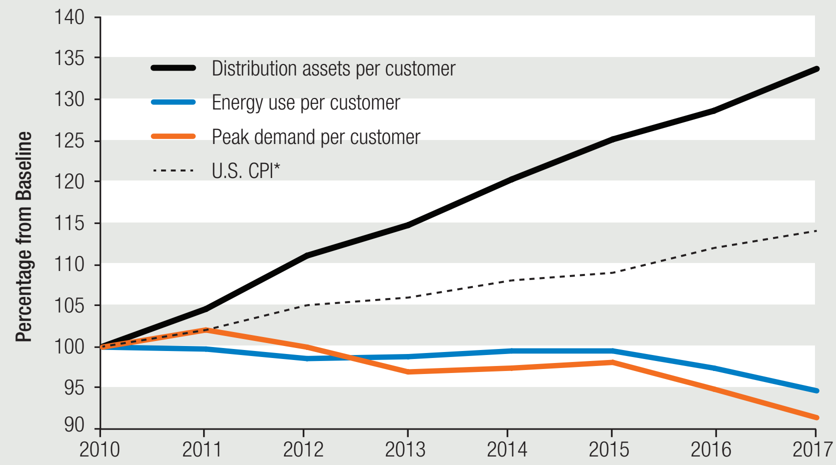
Processes to solicit non-wires alternatives to utility investment are increasingly common components of distribution planning, with third parties interested in offering services as diverse as demand response, energy storage, grid communications services, and cloud computing to name just a few. A diagram of a distribution planning process which incorporates all these components is offered in Figure 1.

See Figure 1.

Monitoring and Performance Measurement:

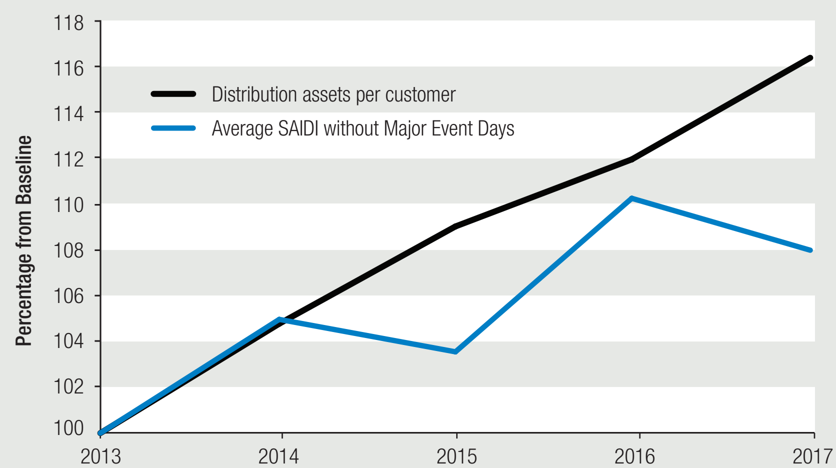
Last but perhaps most important, regulators should specify that grid investment performance will be monitored and measured as part of the distribution planning process. The Ohio PUC reached this conclusion as part of its PowerForward investigation into grid modernization.

Fig. 2 Selected Data, All U.S. IOUs, Baseline = 100



* https://www.bls.gov/data/inflation_calculator.htm

Fig. 3 Selected Data, All U.S. IOUs, Baseline = 100



Sources: FERC Form 1, EIA Form 861

The risk-informed project evaluation, prioritization, and selection process should include estimates of quantified benefits each project is expected to deliver (such as the size of the reduction in adverse event likelihood). The benefit estimates of multiple projects selected for implementation can be aggregated and documented as a target for performance monitoring purposes.

For example, selected grid hardening projects will each have an estimate for System Average Interruption Duration Index improvement; these estimates can be aggregated to establish a SAIDI reduction target for the utility. The process can be repeated for any type of grid project objective, including reduced operating expenses, improved customer satisfaction, or increased distributed generation capacity accommodation.

Grid Modernization Results So Far

Unfortunately, due in large part to a lack of transparent distribution planning processes and performance measurement, grid modernization outcomes appear disappointing so far. FERC Form 1 and EIA Form 861 data submitted by IOUs indicates that despite falling energy use and peak demand, grid investment has outpaced inflation by a ratio of three to one in recent years

See Figure 2.

Yet to date, IOUs do not appear to have fulfilled the promise of grid modernization. Grid reliability, as measured by SAIDI without Major Event Days, appears to be deteriorating.

See Figure 3.

Growth in operations and maintenance spending has generally mirrored inflation, indicating that savings expected from replacing labor with capital have not materialized.

See Figure 4.

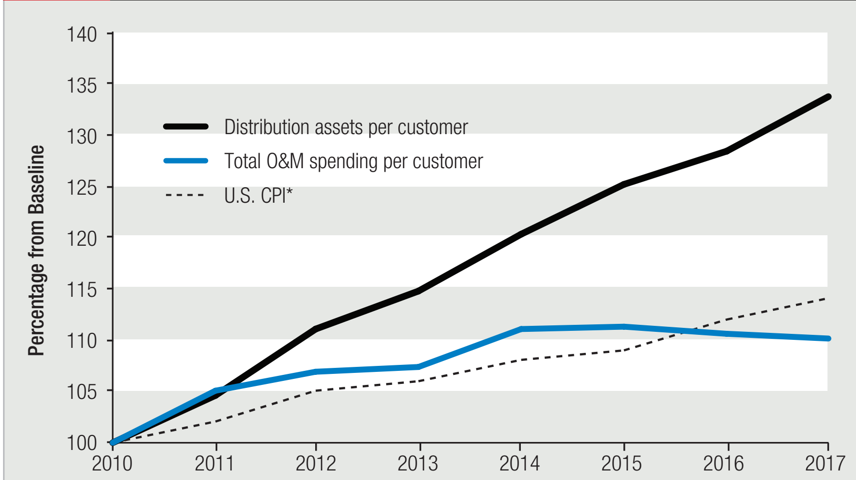
Furthermore, while the Edison Foundation reports that smart meters have now been installed for over fifty percent of U.S households, the Brattle Group reports that only 1.7

(Cont. on page 127)

Rush to Modernize

(Cont. from p. 121)

FIG. 4 SELECTED DATA, ALL U.S. IOUs, BASELINE = 100



* https://www.bls.gov/data/inflation_calculator.htm

Sources: FERC Form 1, EIA Form 861

FIG. 5 CUSTOMER VALUE RANKING

1. Toledo Edison
2. Northern States Power – Minnesota
3. Nevada Power Company
4. Cleveland Illuminating
5. Kentucky Utilities
5. Wisconsin Electric (tie)
7. Public Service Company of Colorado
8. Wisconsin Public Service
9. PPL Electric Utilities
9. Northern States Power – Wisconsin (tie)

percent of U.S. residential customers are billed on a time-of-use rate, implying that smart meters' impact on peak demand has been negligible.

Furthermore, other than isolated cases in which an IOU receives an economic reward for conservation voltage reduction, there is no research indicating that grid modernization has delivered reductions in energy use. Customer value seems to be missing from the grid modernization equation, adding a sense of urgency to the development of distribution planning and performance measurement processes.

In order to encourage responsible grid investment, thoughtful distribution planning, and performance measurement, the authors have used publicly available data from the FERC Form 1, EIA Form 861, and JD Power and Associates to develop a Customer Value Ranking.

An IOU's overall Customer Value Rank is determined by averaging its individual rankings on four metrics, including: SAIDI without major event days; Residential overall satisfaction score, as measured by JD Power and Associates; Distribution rate base per customer (lower is better); and Operations and maintenance spending per customer (lower is better). The Customer Value Ranking thereby offers a rough comparison of bang for the buck, or customer value, delivered by US IOUs.

The ranking methodology incorporates performance metric adjustments calculated through the use of ordinary least squares regression analysis. Performance results were adjusted up or down for various IOU characteristics, based on correlations between characteristics and metrics demonstrated in the FERC, EIA, and JD Power data.

To illustrate, and as expected, FERC and EIA data indicate that IOUs with a lower customer density per line mile have higher rate bases per customer, higher O&M spending per customer, and worse SAIDI on average than IOUs with a higher customer density, and vice versa. (As another example, higher cooling degree days are correlated with higher customer satisfaction scores.) The magnitude of adjustments specified by the regression analysis are relatively small and are based on thousands of observations from 2010 to 2017.

Only U.S. IOUs with all four data points are included in the Customer Value Ranking, amounting to one hundred and four IOUs in the third annual ranking recently completed (based on 2017 data). Congratulations are offered to the ten U.S. IOUs that delivered the best SAIDI and the highest customer satisfaction score for the lowest rate base and O&M spending per customer in 2017. See Figure 5.

Congratulations are also in order for holding companies with multiple top-ten placements in the Customer Value Ranking, including First Energy - 2, Xcel Energy - 3, and PPL Corp - 2. For more information on the Customer Value Ranking methodology, individual ranks in each of the four metrics, and full rankings for 2015, 2016, and 2017, please visit www.utilityevaluator.com.

Development of distribution planning and performance measurement processes will not be easy, but this observation is insufficient justification for ignoring the opportunity and responsibility. Moderation of capital requirements and maximization of customer benefits should make planning process development and performance measurement very worthwhile endeavors.

If risk-informed decision support were applied to regulators' own project lists, the authors believe distribution planning process development and performance measurement would land near the top. PUF