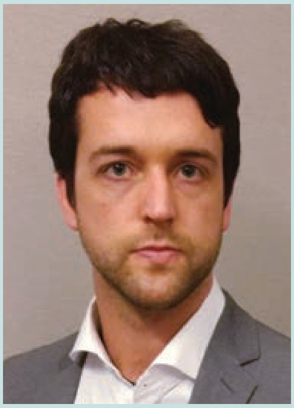
Asset Replacement Based on Risk Modeling

Emerging Practices in Customer Benefit and Cost Estimation

Part II

By Paul Alvarez, Sean Ericson, and Dennis Stephens of the Wired Group

As reported in Part One of this two-part series in the most recent edition of Public Utilities Fortnightly, state regulators in the U.S. are being asked to consider multi-year, multi-billion-dollar proposals to make reliability-related electric grid investments with increasing frequency.

Part One described how IOUs, aided by their experts and software suppliers, are turning toward subjective risk modeling to identify assets for prospective replacement, rather than relying on objective best practices like asset testing, formal inspection, and historical performance observation.

The authors provided evidence that subjective modeling results in far more extensive asset replacement than standard, objective industry practices dictate. As a result, the authors conclude that asset failure rate reduction estimates, and associated reliability improvement projections, are therefore commonly and significantly exaggerated.

In Part Two we will examine common weaknesses in the methodologies IOUs employ when developing benefit-cost analyses for grid investment proposals. First is a critique of how IOUs translate reliability improvements into dollar-denominated economic benefits to customers and communities. In particular, we will examine the deficiencies in the data used in the U.S. Department of Energy's online Interruption Cost Estimator tool.

Next, we'll consider the detrimental impact to communities and economies of rate increases, which IOU benefit-cost analyses tend to ignore. Finally, we'll describe the customer cost impact of carrying charges, and how IOUs typically avoid including them in benefit-cost analyses. The two-part series concludes with the authors' annual ranking of U.S. IOUs by customer value delivered.

Translating Reliability Improvements into Economic Benefits

Most IOUs estimate the improvement of grid hardening investments in customer interruptions (CI) and Customer Minutes Interrupted (CMI). This, in itself, can be misleading, and leads to poor performance accountability, because regulators typically gauge an IOU's reliability performance in terms of System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index or SAIDI.

Regardless of this limitation, with CI and CMI improvement estimates in hand, IOUs typically multiply CI and CMI by the opportunity costs by customer class as established through secondary research by Lawrence Berkeley National Laboratories (LBNL). Outage costs for the Commercial and Industrial (C&I) customer class are based on IOU-administered customer surveys conducted from 1989 to 2005 and updated in 2015 with two more IOU surveys. While this sounds like a reasonable approach, the devil is in the details.

The LBNL researchers clearly point out the limitations of the customer survey data used to establish opportunity costs per CI and CMI, particularly with respect to commercial and industrial customers. For example, only thirteen C&I surveys were conducted from 1989 to 2005 by ten utilities. In the 2015 update, only two more survey projects were added. Significantly, the surveys were not double-blinded; C&I respondents knew their utilities were administering the surveys, and may have exaggerated opportunity cost estimates as a result.

Paul J. 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 in economics at the University of Colorado who specializes in energy industry econometric analyses.

Part Two examines common weaknesses in methodologies IOUs employ when developing benefit-cost analyses for grid investment proposals.

In addition to these facts, the surveys were not geographically representative, nor were they representative of C&I customers. The C&I surveys were only administered to manufacturing and retail customer types, which today represent a minority of non-residential customers. Consider an agricultural C&I customer who uses electricity for irrigation; a service outage incurs zero cost, as irrigation can simply occur later in the day, or can be doubled the following day. Yet such a customer is assumed to secure the same benefits from reliability improvements as other C&I customers.

Further, only one of the surveys attempted to estimate the customer cost of service outages longer than twelve hours (twenty-four hours), with six survey projects limited to four-hour durations and five to eight-hour durations. The researchers pointedly note that opportunity costs per CMI should not be applied to longer duration outages. This is because opportunity cost per minute falls as outages lengthen, due to the actions C&I customers take in response to longer-duration outages. Yet, all IOUs extrapolate the data to longer-duration outages at will.

Another significant shortcoming is there was no consistency in how survey respondents took back-up generation and uninterruptible power supplies (UPS) into account when making outage impact cost estimates. Recent primary research indicates that forty-nine percent of retail facilities and sixty-six percent of manufacturing facilities had both UPS and back-up generation. Yet the typical IOU benefit calculation credits full avoided cost benefits of CI and CMI reductions to such customers.

Further, the avoided cost benefits are large, estimated at $12,952 dollars for a momentary interruption (less than five minutes) applied to all large C&I customers, defined as those consuming fifty thousand kilowatt-hours per year or more. This expansive definition of the type of customer counted as securing $12,952 dollars in benefits per CI reduced presents yet another benefit overstatement.

As a comparison, the average U.S. household consumed 10,972 kilowatt-hours in 2018, meaning that a "large" C&I customer was defined at a size of less than five average households. It is hard to understand how a C&I customer of such a small size could incur a $12,952-dollar cost for each momentary service interruption.

These limitations, all of which overstate the benefits to customers per CI and CMI reduction, have not discouraged IOUs from using them to estimate benefits. Nor have they discouraged the U.S. Department of Energy from using the estimated costs to customers per CI and CMI in its popular online tool, the Interruption Cost Estimator.

Yet there is an additional, fundamental flaw in how IOUs use these customer cost estimates per CI and CMI from the LBNL secondary research. The surveys on which LBNL completed its secondary research were designed to estimate the costs to an individual C&I customer of service outages of various durations.

It is inappropriate to aggregate individual C&I customers' avoided costs into an overall, community-wide benefit estimate without considering countervailing beneficial impacts to C&I customers not impacted by a local service outage. Consider, for example, a residential customer faced with no electricity for cooking and air conditioning; he or she may decide to go out to dinner, to a shopping mall, or to a movie theatre, benefitting some C&I customers. Or, consider a motorist in need of gasoline, who bypasses a gas station without power in favor of a gas station with power.

Any outage cost methodology that only looks at the costs to C&I customers impacted by an outage, without also looking at the benefits to nearby C&I customers who have not lost power, surely over-estimates the overall costs to a community from an outage, and therefore the benefits to a community of reductions in CI and CMI. To address some of these deficiencies, the authors reluctantly recommend regulators demand that IOUs use the Department of Energy's Interruption Cost Estimator – commonly known as the ICE Tool – to translate reliability improvements into economic benefits.

The ICE Tool is based on the same flawed opportunity costs per C&I customer CI and CMI described earlier. As the ICE Tool is based on exaggerated opportunity costs, it exaggerates economic benefits, which is why the authors hesitate to recommend it.

However, the ICE Tool does remedy some of the flaws associated with the use of the LBNL opportunity cost estimates for C&I customers. As a result of these remedies, the ICE tool is probably more accurate than the unrestricted use of such opportunity costs in IOU's self-calculated benefit estimates. One flaw the ICE Tool remedies is the requirement to input reliability improvements in SAIDI and SAIFI terms. This is important for holding IOUs accountable for post-investment performance.

The ICE Tool also makes some adjustments that reflect the opportunity costs reductions from prevalent adoption of back-up generation and uninterruptible power supply among C&I customers. As a result, the ICE Tool will always deliver more realistic economic benefit estimates than the estimates from IOUs that do not use the tool, though the authors continue to believe the ICE Tool exaggerates economic benefits for the multiple reasons discussed above.

Understating costs has profound implications for IOU benefit-cost analysis.

The ICE Tool also translates economic benefits over the life of the new assets into present value (reflecting the time value of money, time-based risk premiums, etc.), which is the most appropriate way to calculate both benefits and costs in a benefit-cost analysis. While this is a handy feature, the subject of the discount rate to use in a present value calculation is controversial, and we will return to this subject.

In the long run, the only way to correct the deficiencies in estimated C&I customer opportunity costs per CI and CMI reduction is to conduct an independent, primary research project focused on the relevant, unanswered question: what are the community-wide economic opportunity costs of electric service outages of various durations and extents?

The authors understand the U.S. Department of Energy is attempting to secure funding for such a project, and hope that this article prioritizes the project at a higher level. In the meantime, there are other economic benefit exaggerations regulators should address, including the techniques IOUs employ to estimate the ripple effects of reliability improvements or capital spending throughout an economy.

Estimating Ripple Effects of IOU Spending/Reliability Improvements

The second flaw in benefit-cost justifications is introduced by IOUs when they attempt to add state-wide economic ripple

Fig. 1 **Significance of Failing to Include Carrying Charges in Customer Cost Estimates**

($ in millions)	Nominal Value without Carrying Charges	Nominal Value with Carrying Charges	Present Value without Carrying Charges	Present Value with Carrying Charges
Customer Cost Estimate:	$3,609.5	$8,491.7	$2,677.1	$3,600.5

effects of their reliability-related economic benefits or capital investments.

The U.S. Bureau of Economic Analysis (RIMS II) and IMPLAN (commercial software provider) offer software that IOUs utilize to estimate this multiplier effect, which generally ranges from about twenty-five to sixty percent of primary economic benefit estimates related to estimated reliability improvements, or from IOU spending. Some IOUs count both types of ripple effects (spending and reliability improvements) in their benefit-cost analyses.

While the benefits from ripple effects are real, and the authors pass no judgement on these multipliers, it stands to reason that exaggeration in reliability-related economic benefits, when used as model inputs, will also exaggerate economic ripple effects. But this is the least of the problems associated with estimation of economic ripple effects.

While IOUs are eager to tout the favorable community-wide economic impacts of reliability-related benefits and capital spending, they never raise the issue of economic detriments associated with the rate increases required to pay for IOU capital investment plans.

In the authors' experience, multi-billion-dollar, extraordinary grid investment plans typically result in rate increases of twelve percent to fifteen percent or more and will persist until the new assets are fully depreciated (generally about thirty years). These increases will be on top of routine rate increases an IOU will require over time.

Electric rate increases drain the economy, and the economic competitiveness of U.S. industry, in many ways. Governments may need to raise taxes or reduce services; businesses may choose to transfer operations to states or nations with lower power costs; and consumers have less discretionary income.

Neither the RIMS II nor IMPLAN models IOUs employ to estimate ripple effect benefits can be used to estimate the detrimental impact of rate increases. Nor do IOUs ever attempt to estimate the detrimental impact of rate increases, for obvious reasons.

As a result of this significant oversight, the authors recommend regulators completely ignore any favorable community-wide ripple effects an IOU might include in benefit-cost analyses. By ignoring economic ripple effects, regulators will be appropriately accounting for the fact that such benefits are almost certainly outweighed by the economic detriments of grid hardening rate increases which IOU analyses ignore.

Including Carrying Charges Customers Pay in Cost Estimates

This brings us to the third flaw in IOU benefit-cost analyses: ignoring carrying charges customers must pay as part of rate increases from IOU investments.

When comparing customer benefits to costs, IOUs always estimate costs as their own capital and operations and maintenance (O&M) spending. This is clearly inappropriate; the most relevant cost to compare customers' benefits are customers' costs, not IOU costs.

Carrying charges include all costs customers must cover to ensure the IOU has a reasonable opportunity to earn its authorized return on capital.

The costs customers must pay on IOU investments are much greater than the cost of those investments to the IOU, as they include carrying charges to ensure the IOU has a reasonable opportunity to earn its authorized return on capital.

Carrying charges include much more than just the authorized return on capital itself. Carrying charges also include all costs customers must cover to ensure the IOU has a reasonable opportunity to earn its authorized return on capital.

These include federal income taxes (twenty-one percent of the authorized return) and sometimes state income taxes; interest expense (typically about three to four percent on capital these days); local property taxes assessed on fixed assets; sales taxes in many states; municipal franchise fees; and sometimes fees to fund state regulators and consumer advocates. These charges are enormous over time, as they are based on the outstanding capital balances each and every year until the new assets are fully depreciated.

Figure One illustrates the significance of failing to include carrying charges in customer cost estimates. Given the reasonable assumptions listed below the table, it is easy to see how the failure to include carrying charges can underestimate nominal value customer costs by two times, and present value customer costs by thirty-five percent.

See Figure One.

Note: Nominal Values are expressed in today's dollars; Present

Gas Ban as Confiscation of Property

(Cont. from p. 67)

Service Commissions to replace retired assets and to accommodate growth. In all cases, new investment was contemplated and the regulatory scheme including depreciation policy was based on that assumption.

Under those assumptions, investors accepted the notion that stranded costs would be recovered at original cost as new capital would become available to support new investment and future earnings.

To repeat, regulation including depreciation policy has been based on the assumption that the public utility has an indefinite or perpetual service obligation. The recent move by municipal governments to abolish gas distribution service by some date certain is another matter entirely.

The move to ban gas service is more akin to the exercise of eminent domain. In both cases the investor loses control of the assets involuntarily and with that also the opportunity to earn the future income generated by those assets.

Thus, the gas utility investor is put in a different position with electrification than under all prior stranded cost experience where the enterprise continues in business and the current customers remain customers into the future.

The damage to the investor in this new scenario should be measured similarly to the other case where assets are removed along with the associated customers. That is the case of an eminent domain action where the municipality takes over the ownership of the utility assets from the private investors.

Under an eminent domain proceeding the compensation to the investors would be at fair value and not original cost. A sequenced electrification of gas services across a municipality could therefore be viewed as a sequenced condemnation. The cost of such electrification to the municipality under fair value would require a significantly different analysis than the one offered citizens today. PUF

Alberta Commission Chair Retires

(Cont. from p. 57)

I wanted the Commission to be able to work with the industry to understand the implications of distributed energy resources on the efficiency of the grid and the recovery of embedded costs. Too many times, regulators and policymakers end up chasing market trends, rather than getting in front of them. I did not want that to happen in Alberta. I look forward to seeing the inquiry report.

Ahmad Faruqui: What's next for you?

Mark Kolesar: Well, I am not ready to retire yet. It is an exciting time to be in the utility regulation arena. I have a lot to contribute to that arena, and I hope I will find opportunities to do so. At this stage of my career, I hope to collaborate on intellectually interesting research and consulting projects. PUF

Asset Replacement

(Cont. from p. 76)

IOU rankings for each of the four individual metrics, as well as Customer Value Rankings of all qualifying U.S. IOUs 2016-2019 (generally about one hundred in number), are available online at www.utilityevaluator.com/customer-value-rankings.html.

The authors calculate and release the Customer Value Ranking early in each calendar year. Top decile electric distribution IOUs in the 2019 Customer Value Ranking are found in Figure 2.

See Figure Two.

The authors congratulate these IOUs for their focus on delivering customer value per dollar. We encourage all IOUs to benchmark their own performance against the leaders in each metric, and to identify and emulate the leaders' best demonstrated practices as appropriate. PUF

FIG. 2 2019 IOU CUSTOMER VALUE RANKINGS

1. Florida Power and Light and Toledo Edison (tie)
3. Nevada Power Company
4. Wisconsin Public Service
5. MidAmerican Energy
6. Wisconsin Electric and Indianapolis Power & Light (tie)
8. PPL Electric Utilities
9. Dayton Power & Light
10. Ohio Edison

Values account for the impact of inflation, the time value of money, and risk premiums. IOUs typically use either or both in benefit-cost analyses. In a benefit-cost analysis, nominal costs should only be compared to nominal benefits, while present value costs (including carrying charges) should only be compared to present value benefits.

Carrying charge assumptions used to calculate customer costs:

IOU debt ratio 47 percent (equity ratio 53 percent);

IOU interest expense 4.5 percent;

IOU authorized rate of return on equity 10.3 percent;

Federal income tax rate 21 percent;

State sales tax rate 4 percent;

Asset depreciation period thirty years; and

Discount rate 6.8 percent (for present value calculations);

Understating costs has profound implications for IOU benefit-cost analysis. The immediate concern is that it provides an inaccurate basis against which to compare benefits. For example, an IOU need show fewer benefits to achieve a favorable benefit-to-cost ratio when costs are understated.

Not only can this lead to bad decisions when regulators rely upon them, it can lead to regulators holding an IOU accountable for securing lower benefits than might otherwise be called for.

The failure to include carrying charges in economic analyses involving IOUs has even greater consequences, however. Consider the make versus buy analyses, which should be completed when comparing the customer cost of an IOU's investment to the customer cost of a third-party service provider.

The price quotes from such service providers – be they providers of a non-wires alternative, data communications services, or software as a service – undoubtedly must cover those providers' income taxes, interest expense on debt, property taxes, and a return on investment for the third parties' equity investors. By comparing providers' service prices to customer costs for IOU investments that do not include carrying charges, bias in favor of IOU investment is clear.

It is therefore important to set a precedent for including carrying charges, over the life of grid hardening assets until fully depreciated, in all economic analyses involving IOU investments.

Finally, when converting both customer costs and customer benefits into present value, regulators may wish to examine the discount rate critical to this conversion. An IOU's weighted average cost of capital is traditionally used as the discount rate, as this reflects an IOU's opportunity costs of raising new capital (vs. paying down debt).

The authors contend that, as this is a customer-focused analysis, a more appropriate discount rate to use is the customers' (average) cost of capital. As rate increases deprive customers of the opportunity to pay down debts, it is more appropriate to use customer cost of capital, not utility cost of capital, as a discount rate in present value calculations.

Authors' 2019 IOU Customer Value Rankings

This two-part article is an editorial on emerging trends and best practices in the evaluation of extraordinary grid investment proposals by U.S. IOUs. It encourages state regulators to make rigorous technical and financial evaluations of such proposals to help ensure that investment plans are likely to deliver customer benefits in excess of customer costs.

It is more appropriate to use customer cost of capital, not utility cost of capital, as a discount rate in present value calculations.

To further encourage cost-effective IOU investment, the authors calculate and issue a customer value ranking annually. The annual ranking is the authors' continuing attempt to bring stakeholder and state regulator attention to the issue of customer value creation per dollar of IOU spending, and to encourage performance measurement and benchmarking.

The ranking is developed using IOU-provided, publicly available financial and operating data from FERC Form 1 and EIA Form 861. The ranking identifies the IOUs that provide the greatest benefits to customers, as measured by reliability (SAIDI without Major Event Days) and customer satisfaction (JD Power Overall Residential Satisfaction Scores), for the least amount of cost, as measured by capital spending (gross distribution rate base) and O&M spending per customer.

The resulting Customer Value Ranking is a simple addition of IOUs' ranks in each of the four metrics. Regression analyses are used to adjust rankings in each individual metric for any statistically significant correlations to utility characteristics, such as customer density per line mile, peak demand per customer, or heating and cooling degree days, found in the data.

As described in the authors' previous work however, such correlations are few and weak, resulting in minimal changes from unadjusted rankings. IOUs missing any one of the four metrics are not included in the ranking.

(Cont. on page 81)