

# Performance Incentives for Cost-Effective Distribution System Investments

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## Introduction

This policy brief is a generic version of a memo provided for a state public utility commission, considering starting points for how to apply performance-based regulation (PBR) and associated performance incentive mechanisms (PIMs) to distribution system investments by utilities. Ensuring that such investments are cost-effective begins by outlining goals that a state utility commission might want to achieve regarding two core regulatory functions: ensuring distribution system reliability and controlling costs. Those goals can then be refined into performance criteria, which specify how the goals will be monitored or achieved from an operational standpoint. The final step is to settle on metrics to be used to measure progress toward those performance criteria, and thus outcomes consistent with the broader regulatory goals of ensuring reliability at a just and reasonable rate.

## A Performance-Based Approach to Distribution System Investments

### Regulators Need Good Data, Analysis and Presentation

If basic data are lacking on distribution system performance, it is difficult to assess that performance, and it can be hard to even set performance criteria. The first step is to assess data available in existing rate cases, distribution plans, integrated resource plans, filings by the Federal Energy Regulatory Commission (FERC) or regional transmission operators/independent system operators, and related dockets. Data on overall and per-unit costs may be available in these dockets or may be calculated from data provided by the utility or regulator.

If the basic data are simply not available, then the regulator can confer with the utility and stakeholders, preferably in sessions held with public notice, to consider gathering the appropriate data to report on the status quo (baseline) conditions as well as to track progress toward goals. Considerations in collecting and analyzing data sets should include representativeness, objectivity and lack of susceptibility to manipulation. The regulator also must ascertain whether data collection can be done through automated systems such as hourly or subhourly load shape by circuit, as well as the costs of setting up those systems and maintaining the datasets. Finally, the data must be maintained and presented for review in formats that allow operators to manage data inputs from utilities and regulators, so they can perform their oversight and compliance role with minimal administrative effort.

## One Option: Dashboards

Reporting dashboards can provide data collection, analysis and presentation for a PBR approach. In this context, a “dashboard” refers to a summary table in accessible graphic format, compiling data in a form the public can understand. Dashboards provide a way to inform regulators, the public and stakeholders of utility progress toward important goals. Just the collection of data and public reporting via a dashboard might be enough to motivate utility progress toward the goals.

## When Dashboards Don’t Work, Incentives May Work

A dashboard approach is less likely to succeed where it is not in the utility’s economic interest to pursue particular goals, such as implementing energy efficiency or accommodating distributed energy resources (DERs), that reduce utility sales and thus revenue. In such cases, the utility may need incentives to pursue these goals, such as additional earnings or rate of return. With a performance incentive set at the right level, the utility will see pursuing a goal such as efficiency or DER integration as conducive to its business interest in growing and maintaining revenue.

## Goals

Overarching PBR goals recognize that investments in distribution infrastructure are necessary, yet seek to measure the effect of those investments in terms of cost-effectiveness per unit, reliability improvements and safe electrical service. Goals for a PBR approach to distribution system investment that focuses on cost-effectiveness and reliability could include:

**Focus directly on customer costs:** There are several ways to focus on distribution system cost to consumers: a) adopt a goal to reduce or limit increases in customer bills, b) adopt a limit on rate increases, c) limit increases in distribution rate base, or d) limit increases in the utility’s revenue requirement. The goal is to maintain customer costs or limit customer cost increases through slightly different performance criteria (see below).

**Focus goals on cost transparency:** Create a transparent cost accounting scheme for distribution system improvements to allow ratepayers and the public to understand why and how much they are paying for various improvements to the grid. This accounting should include the nature of the improvements, including reliability and increased capacity. Cost-per-project bases are

already available in part in utility rate case filings, but are buried in testimony that is hard for customers to access and understand.

**Focus on cost data development (performance cost transparency):** If data are insufficient to assess performance costs, regulators may need to mandate that utilities collect and report data to create cost-effectiveness baselines. These can be used to evaluate targets, performance criteria and metrics that are in turn used to track distribution system improvement costs by upgrade, circuit, feeder or customers served. This “performance cost transparency” is useful not just for PBR, but for plain vanilla cost-based regulation as well.

**Use data to create performance criteria:** With a sufficient dataset, regulators can create a set of cost baselines or performance criteria for electric distribution companies. These baselines can then be used by utilities to strive to improve through efficiencies, superior management and better deployment of staff, contractors and utility resources.

**Improve traditional safety measures systemwide:** Reliability improvements throughout the system can be clearly stated as utility goals with metrics.

**Address reliability by focusing on poorly performing circuits:** It is common for telecommunications providers to identify poorly performing circuits to regulators. While this is not so common in the electrical utility sphere, regulators could focus on improving poorly performing electric circuits. The goal could be to improve how reliability and resilience are measured on a circuit-by-circuit basis and to highlight improvements by circuit and feeder. Reliability metrics are already measured systemwide, so the goal under this category could be to move to tracking at a more granular level the need for improvements, costs incurred to fix and upgrade particular circuits, and whether upgrades result in improvements in particular circuits or feeders.

## Performance Criteria

After there is a consensus on goals to be pursued, whether by statutory mandate or commission practice, and evaluation of measurable performance criteria, the next step in a successful PBR scheme is to articulate how to achieve those goals.

Performance criteria to implement goals such as those described above could look like the following:

- Utilities will track and report costs of distribution system improvements on a per-unit basis, clustering similar projects together for comparability across utilities, geography and time. This will enable accurate measures of distribution system investment by circuit, mile of feeder (low-voltage transmission system), sub-transmission (high-voltage distribution system), substation, per ratepayer, or other relevant units of measurement.
- Utilities will measure distribution system reliability performance by utility system, circuit and feeder.
- Utilities will measure distribution system resilience by circuit or feeder, e.g., ability to recover from outage.

- Utilities will measure improvements in the System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI) and other measures of reliability by circuit, feeder, or more granular level to isolate the impact of distribution system upgrades. Unlike the previous two criteria, this measurement would not just look at trends, but specifically assess improvements as a result of distribution system improvements/investments and/or forestry (tree-trimming) projects.
- Utilities will improve poorly performing feeder(s) and circuits.
- Utilities will assess cost-effectiveness of forestry work by region, circuit, feeder or more granular level on a unit, per-mile basis.
- Utilities will assess the cost-effectiveness of forestry work by region, circuit, feeder or more granular level improvements to SAIDI, SAIFI, and CAIDI on a per-unit basis or by circuit or feeder.
- Utilities will compare the cost-effectiveness of forestry operating expenditure (OPEX) to distribution capital expenditure (CAPEX) in achieving reliability improvements.

These performance criteria can be further refined to be measurable using the following ratios, formulas or methodologies to derive costs per customer, cost per unit of upgrades or improvements by circuit:

- Distribution plant/assets per customer by rate class, per mile and per MWh, perhaps differentiated by rural, suburban, and urban areas.
- Cost per unit of distribution plant installed by year, feeder mile, substation upgrades, and pole top replacement.
- O&M spend per customer for distribution (divided by line size, circuit type), generation and transmission.
- Total energy costs per customer.
- Total capacity costs per customer.
- Service reliability (frequency, duration, SAIDI, SAIFI, CAIDI, etc.) by feeder and circuit.
- System losses (total losses/MWh generation) and losses by distribution circuit or bulk system — additionally separated by seasons and time of day (peak/off-peak), since losses vary greatly based on system loading and temperature.
- Improvements for poorly performing feeder(s) in the bottom 5% to 25% range. The regulator would need to identify the ranges of interest and focal point for improving service and any associated equity issues for underserved rural and urban communities.

When general directional indicators under performance criteria are settled on, then metrics based on those data can be assessed for those most likely to provide accurate measures of progress under each performance criterion — and thus toward the overall goal.

# Metrics

After setting forth the goals and clarifying the performance criteria to measure progress toward those goals, a process would occur to recommend a set of metrics to guide collection of information, assessment and measurement progress, and performance under each goal and performance criterion. In our experience, this process is more likely to meet with long-term stakeholder acceptance if it is public and receives substantial stakeholder input.

These metrics could be categorized into the following categories:

- Total distribution system cost per customer annually (CAPEX + OPEX), as reported for Securities and Exchange Commission (SEC) and FERC purposes.
- Average customer bill by rate class, identifying low- and moderate-income (LMI) ratepayers as a subclass of residential classes where possible.
- Average annual bill as a percentage of income by residential class, identifying LMI ratepayers separately where information is available.
- Cost per mile of distribution and transmission line re-conducted: presented separately for each kW line type.
- Cost per mile for a new line/feeder: presented separately for each kW line type.
- Cost of make-ready work per new interconnection: by size levels kW of system interconnection level, e.g. below 100 kV, 101 kV to 1 MW, 1 MW to 5 MW, above 5 MW.
- Cost of new substation built or substation replacement, sorted by standard step-up and step-down substations and number of circuits in or out of a substation.
- Power quality measured as changes in voltage, or number of validated complaints to the public service commission, or measured exceedance or dips in voltage above and below standard.
- Distribution lines controlled with automated power quality equipment: Tally the number or percentage of lines with voltage and volt-ampere reactive controls, and compare power quality on these lines to power quality without improvements.
- Distribution system visibility and reliability: Tally the number or percentage of feeders, substations, distribution circuits installed with operational supervisory control and data acquisition (SCADA) or other visibility combined with automated or centralized control measures, and compare the reliability of feeders, substations, and circuits with and without SCADA and automated controls.
- SAIDI, SAIFI, CAIDI and other traditional and standardized reliability metrics.
- Momentary Average Interruption Frequency Index (MAIFI): Total number of momentary customer interruptions.
- Customers Experiencing Lengthy Interruption Index (CELID).
- Customers Experiencing Multiple Interruptions Index (CEMI).

- **Reduced outage impact:** circuit average interruption duration index for grid-modernized feeders/circuits.
- **Identify the worst-performing feeder(s),** such as the bottom 5-25%, and track improvements in the bottom percentage or those with distribution system investments each year.

## Conclusion

In a competitive market, companies can increase sales, revenue and customer base either by providing superior service at a comparable price, or by providing better pricing for a comparable service. Because utilities are natural monopolies, customers cannot move to another company if their service is subpar or their pricing is above a reasonable benchmark. The goal of utility regulation, as established at the turn of the 20<sup>th</sup> century, is to replicate outcomes for monopolies that a competitive market would provide: safe, reliable service at a just and reasonable price.

Yet utility regulators often focus on the cost of providing service (the inputs) rather than the results of whether that service is provided in a cost-effective manner (the outputs). Regulators have focused in particular on reliability with basic measures such as SAIDI, SAIFI and CAIDI. Even there, the actual details of the metric formula across jurisdictions and even across utilities in the same jurisdiction vary, meaning that reliability measures are not comparable across jurisdictions. A regulator in state A cannot compare the overall reliability outcomes of four utilities in that state to the reliability outcomes of four utilities in state B. The inability to compare costs of basic distribution infrastructure is even more marked. Regulators have no basic cost figures to assess utilities that demonstrate superior performance with grid upgrades and replacements versus those that manage projects poorly with costs higher than average. There is no way to measure average — no baseline at all across jurisdictions.

This paper proposes a way to develop measures to assess superior vs. subpar electric distribution system performance on cost control and reliability — at a bare minimum to set baselines for regulators to track cost trends of the same utility. If regulators seek to use better data and metrics to create performance incentives for more cost-effective management of distribution infrastructure, analysis of goals, performance criteria, metrics and data reported under that structure would provide a basis for a system to replicate the competitive pressures of the market. Even without incentives, reporting on reliability and cost control can itself enable smarter regulation and more transparency to customers with regard to the value of utility services.



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