

CALIFORNIA INVESTOR OWNED UTILITY DISTRIBUTION AND TRANSMISSION COST BENCHMARKING

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CONTEXT

In recent years, California's electricity rates have grown more rapidly than in past decades, prompting questions about the drivers of rate growth, and whether those drivers are unique to California. This analysis seeks to compare California's investor owned utilities¹ electricity distribution and transmission costs to costs of other peer utilities in the US, not only in recent years but also going back in time, to understand a) whether California's costs are in fact higher on a unitized basis, and b) if California's costs are higher, how long that trend has been present.

ANALYTICAL APPROACH AND DATA SOURCES

All investor-owned utilities in the US are required to report financial data annually through FERC Form 1. Select FERC Form 1 schedules have been compiled and made accessible in the Public Utility Data Liberation Project (PUDL) created by Catalyst Cooperative.² We used the PUDL database to download annual utility data from 1994 to 2024, reporting annual electric distribution and transmission operations and maintenance expense (Schedule 320) and annual distribution and transmission depreciation expense (Schedule 336) for each of the three California IOUs and a set of peer utilities, shown in Table 1 below.

TABLE 1. *Peer Utility Group*

UTILITY	STATES OF OPERATION (AS OF 2025)
Consolidated Edison (Con Edison)	New York
Idaho Power Company	Idaho
Massachusetts Electric Company (National Grid)	Massachusetts
PacificCorp	Utah, Oregon, Wyoming, Washington, Idaho, California
Portland General Electric (PGE)	Oregon
Public Service Company of Colorado (PSCo/Xcel Colorado)	Colorado
Public Service Electric & Gas Company (PSEG)	New Jersey
Virginia Electric & Power (Dominion)	Virginia

We selected the peer utility group with awareness of a handful of factors that are often anecdotally cited as drivers for California's relatively high electricity costs: high wildfire risk, mountainous terrain, high population density, and overall utility size (PG&E and SCE are among the largest utilities in the country in terms of number of customers served). We sought to compare the

1 California's investor owned utilities (IOUs) are Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

2 Online database available at <https://catalyst.coop/pudl/>

California IOUs to peer utilities also subject to those hypothetical drivers: Consolidated Edison (Con Edison), Massachusetts Electric, and Public Service Electric & Gas Company (PSEG) serve high-population density territories; Idaho Power, PacifiCorp, Portland General Electric, and Xcel Colorado serve mountainous areas with high wildfire risk; Con Edison and Virginia Electric & Power (Dominion) are other large IOUs.

To compare costs across different utilities with different customer bases and system geographies, we unitized reported costs. We used a different unitization methodology for distribution and transmission costs.

DISTRIBUTION COST UNITIZATION

We unitized distribution costs using the number of miles of distribution lines operated by each utility. To our knowledge, utilities are not required to report the number of distribution line miles they operate in any systematic way. We sourced current approximate statistics for distribution line-miles from a variety of utility publications, including investor reports, fact sheets, and general rate cases, shown below in Table 2.

TABLE 2. *Miles of Distribution Line by Utility*

UTILITY	MILES OF DISTRIBUTION LINE (AS OF 2025)	SOURCE
Consolidated Edison Co-NY Inc	131,500	Corporate fact sheet (2025), press release (2001) ³
Idaho Power Co	27,000	Idaho Energy Landscape publication (2022) ⁴
Massachusetts Electric Co	18,000	Rate case factsheet (2024) ⁵
Pacific Gas & Electric Co.	106,681	Fact sheet 2025 ⁶
PacifiCorp	66,900	PacifiCorp Fact Sheet (April 2025) ⁷
Portland General Electric Co	28,920	PGE Quick Facts (2024) ⁸
Public Service Co of Colorado	80,000	PSCo SEC filing (2024) ⁹
Public Service Elec & Gas Co	22,600	PSEG blog post (2025) ¹⁰
San Diego Gas & Electric Co	16,462	2023 GRC ¹¹
Southern California Edison Co	105,773	SCE careers page (2024) ¹²
Virginia Electric & Power Co	58,000	Dominion Energy Grid Transformation Plan Phase II (2024) ¹³

³ <https://www.coned.com/en/about-us/corporate-facts#:~:text=Con%20Edison%20serves%203.6%20million%20customers%20in, reliable%20electric%20power%20systems%20in%20the%20world>

⁴ <https://oemr.idaho.gov/wp-content/uploads/2022-Idaho-Energy-FINAL.pdf>

⁵ <https://www.nationalgrid.com/document/152991/download>

⁶ <https://www.pge.com/en/about/company-information/company-profile.html>

⁷ https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/about/PacifiCorp_Fact_Sheet.pdf

⁸ <https://portlandgeneral.com/about/info/quick-facts>

⁹ <https://www.sec.gov/Archives/edgar/data/81018/000008101824000006/psco-20231231.htm>

¹⁰ <https://energizepseg.com/2025/10/29/pseg-infrastructure-upgrades-delivering-real-results/>

¹¹ https://www.sdge.com/sites/default/files/documents/S2350002_GRC%20Overview%20FS_FINAL.pdf

¹² <https://www.edisoncareers.com/about-sce/>

¹³ <https://www.dominionenergy.com/-/media/content/about/energy-grid-transformation/voltage-optimization/pdfs/grid-transformation-plan-phase-2.pdf>

We use these mileage values to unitize costs for all years between 1994-2024, meaning we do not account for expansion of the size of distribution systems over that 30-year period, possibly resulting in understatement of distribution costs per mile in the earlier years of the period.

TRANSMISSION COST UNITIZATION

Transmission cost unitization typically accounts for transmission capacity, with costs often reported in dollars per megawatt-mile, to reflect that higher capacity lines are more costly per mile than lower capacity lines. FERC Form 1 (Schedule 422) reports individual transmission segments operated by each utility, with mileage and voltage of each segment reported, but it does not report line capacity. In the absence of capacity data, we used the data from Schedule 422 to calculate total miles of transmission lines operated by each utility at each voltage, and then created a voltage-based multiplier:

$$\text{multiplier} = \frac{\text{weighted average system voltage}^2}{230\text{kV}^2}$$

A system with a weighted average voltage of 230 kV uses a multiplier of 1.0. The multiplier is applied to the reported number of transmission line-miles to calculate voltage-weighted miles for each utility. We scale the multiplier with the square of the system's weighted average voltage to better approximate a transmission line's power transfer capacity.

FERC Form 1 data is available annually from 1994-2024, but the compiled Schedule 422 data in the PUDL database has significant data continuity issues, likely related to inconsistent reporting across utilities and years and changes to reporting formats over time. For each utility, we selected a single recent representative year to calculate the weighted average system voltage. We used total transmission mileage data for all years that it was reported, and assumed that for any year without data available, total mileage was equal to the value from the previous available year.

We removed Con Edison, Massachusetts Electric, Portland General Electric and Virginia Dominion from the transmission benchmarking peer group due to FERC Form 1 data validation issues. We suspect that there may be inconsistency between the FERC cost data sets and the FERC mileage data sets regarding which line voltages qualify as transmission versus distribution; this possible inconsistency is somewhat mitigated by using voltage-weighted miles, discounting low-voltage lines that may be included in the total transmission mileage values but not in the transmission cost data.

Detailed information on reporting year used, total transmission line miles, and voltage-weighted line miles are included in the appendix.

ESTIMATING REVENUE REQUIREMENT

FERC Form 1 records utility financial and operational data. The two financial metrics we focus on in this analysis are O&M costs, which are equivalent to expense costs used in ratemaking, and depreciation expense, which is a representation of capital expenditure that accounts for asset lifetimes and depreciation schedules.

It is useful to approximate revenue requirement from FERC Form 1 data for two reasons: 1) to allow more direct comparison with other pre-read materials prepared for this workshop, which use ratemaking cost data instead of financial data, and 2) to allow comparison of total costs across utilities, normalizing for potential differences in how individual utilities assign costs to expense versus capital.

To approximate revenue requirement, we grossed up depreciation expense to very roughly estimate return on rate base (which is not directly reported in FERC Form 1). We assume that the ratio of return on rate base to depreciation expense for transmission and distribution assets is 1.0; our methodology for deriving that multiplier is detailed in the appendix. Our resulting proxy for revenue requirement is:

$$\text{Proxy Revenue Requirement} = \text{O\&M} + \text{Depreciation Expense} \times (1 + \text{multiplier})$$

RESULTS

DISTRIBUTION

The following Figures 1, 2 and 3 show annual distribution costs per mile for each utility in the selected peer group. Figure 1 shows distribution operations and maintenance (O&M) costs per mile, Figure 2 shows depreciation expense costs per mile, and Figure 3 shows total proxy revenue requirement costs. Costs were converted from reported nominal values to 2024 USD using the national consumer price index.

Comparing these costs over time shows varied trends. In the early years analyzed, California IOUs' per-mile O&M distribution costs are in the middle of the peer group's range; the IOUs' O&M costs (especially SDG&E's) begin to break away from the lower-cost peers beginning around 2004, and then increase dramatically after 2018 in response to wildfires. Depreciation expense for SDG&E has always been on the higher side; while PG&E and SCE's depreciation expenses are in the middle of the peer group in 1994, over time they steadily increase towards the high end of the peer group. Beginning in the 2018-2019 timeframe, PG&E and SDG&E's total costs pull away from the rest of the group's.

FIGURE 1. *Electric Distribution O&M Cost per Line-Mile, 2024 USD*

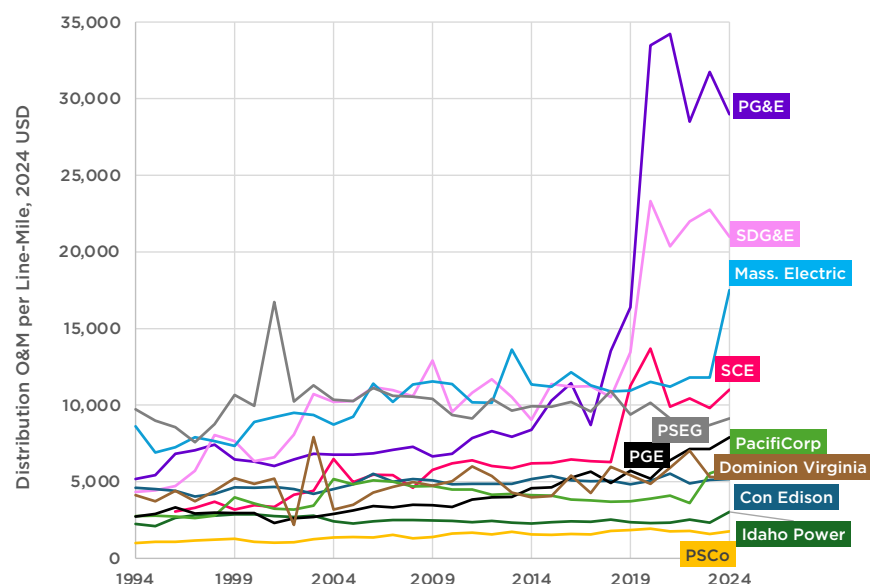


FIGURE 2. *Electric Distribution Depreciation Expense Cost per Line-Mile, 2024 USD*

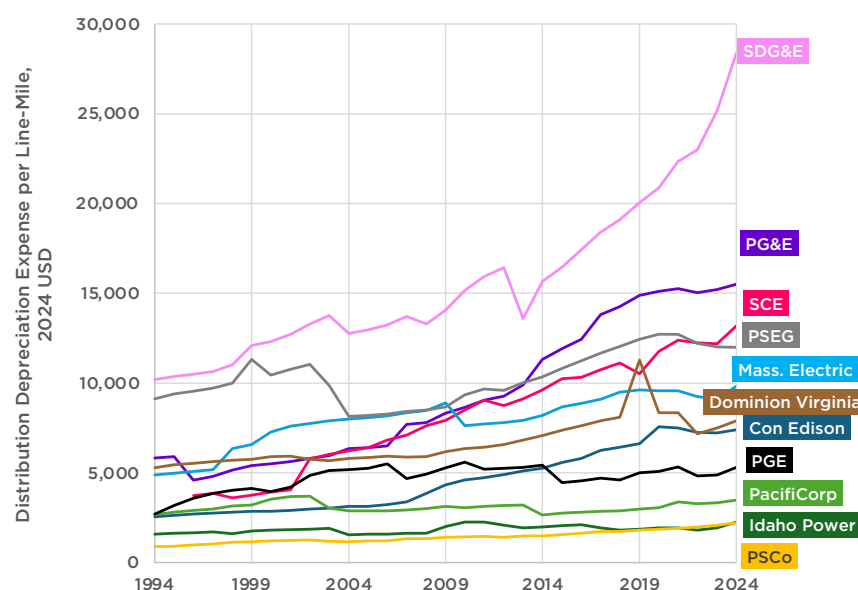


FIGURE 3. *Electric Distribution Revenue Requirement Proxy, Cost per Line-Mile, 2024 USD*

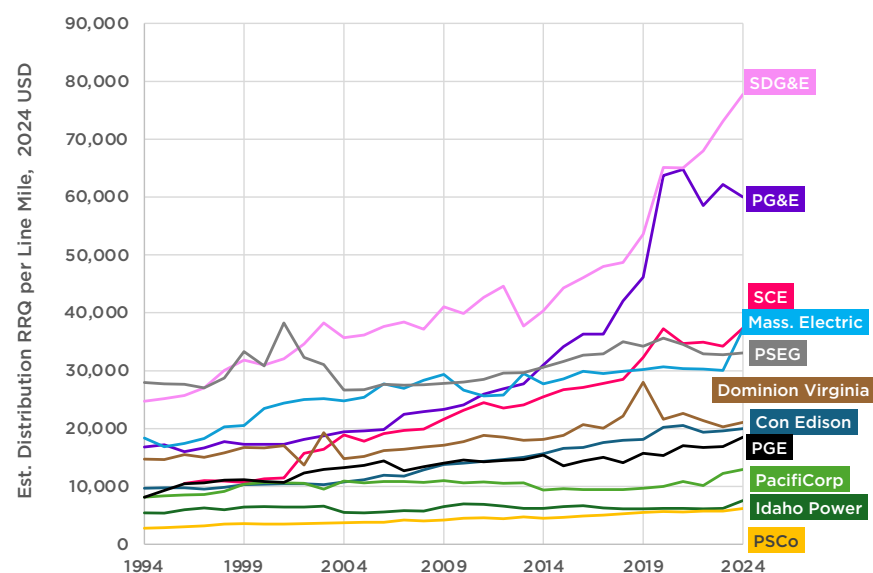
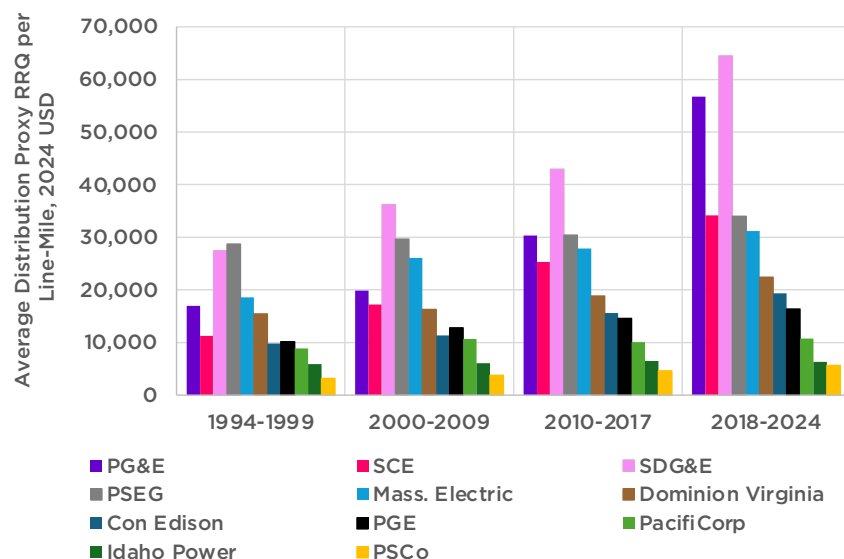


Figure 4 shows distribution O&M and depreciation expense costs per line-mile, averaged across four time periods. These periods are aligned with a companion paper (“An Examination of Rising Electricity Costs and Rates in California”) which identifies four trends (and associated time periods) in California’s distribution cost trajectory: pre-1999 electricity crisis, post-electricity crisis from 2000-2009, rising solar penetration from 2010-2017, and wildfire-dominated investment from 2018-present.

In each period, California IOUs’ distribution costs are among the highest of the peer group, along with PSEG, Massachusetts Electric, and Dominion Virginia. The rapid growth in PG&E and SDG&E’s

costs after 2018 is clearly apparent, but even before wildfire costs begin to dominate trends, the California utilities' distribution costs grow more rapidly than those of the peer group.

FIGURE 4. *Average Annual Electric Distribution Proxy Revenue Requirement, Cost per Line-Mile, 2024 USD*



TRANSMISSION

The following Figures 5, 6 and 7 show annual transmission costs per voltage-weighted mile for each utility in the peer group¹⁴. These figures are analogous to the distribution cost figures in the previous section: Figure 5 shows unitized O&M costs, Figure 6 shows depreciation expense costs, and Figure 7 shows proxy revenue requirement costs. Costs were again converted from reported nominal values to 2024 USD using the national consumer price index.

Like the distribution costs, the California IOUs' unitized transmission O&M costs clearly respond to wildfire events. SDG&E's O&M costs spike dramatically following the 2003 wildfire in their service territory, and PG&E and SCE's costs climb after the 2018 wildfires. Excluding PSEG, the California IOU's O&M unitized transmission costs are consistently the highest in the cohort across the time period.

Similarly, the California IOU's transmission depreciation expense costs are the highest in the peer group across the entire time period excluding PSEG, and increase at a higher rate over time. SDG&E's costs increase steeply between 2011 and 2012, when the \$1.9B Sunrise Powerlink transmission line became operational.¹⁵

The revenue requirement proxy values show that ignoring the temporary increase in SDG&E's O&M costs following the 2003 Southern California wildfires, the California IOU's total unitized transmission costs have grown at a similar trajectory—and have dramatically outpaced the growth of the lower-cost utilities in the peer group (PacifiCorp, PSCo and Idaho Power).

PSEG's total costs are significantly higher than the rest of the peer group's costs, driven by

¹⁴ SCE's transmission costs are not included for 1994 and 1995 due to data issues.

¹⁵ <https://www.eia.gov/todayinenergy/detail.php?id=7050>

rapid growth in reported transmission plant in service beginning in the 2010s, possibly reflecting increased investment in undergrounding and modernization following Hurricane Sandy in 2012.

FIGURE 5. *Electric Transmission O&M Cost per Voltage-Weighted Mile, 2024 USD*

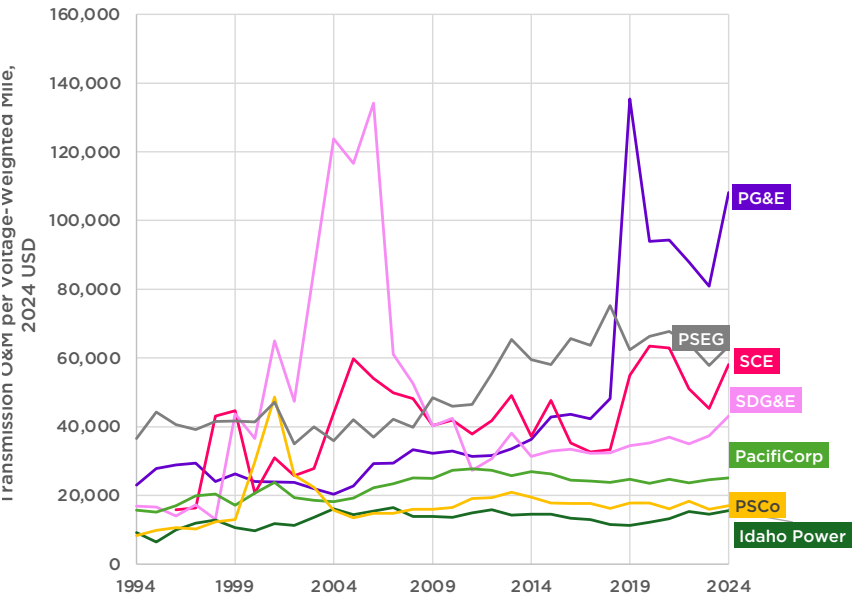


FIGURE 6. *Electric Transmission Depreciation Expense Cost per Voltage-Weighted Mile, 2024 USD*

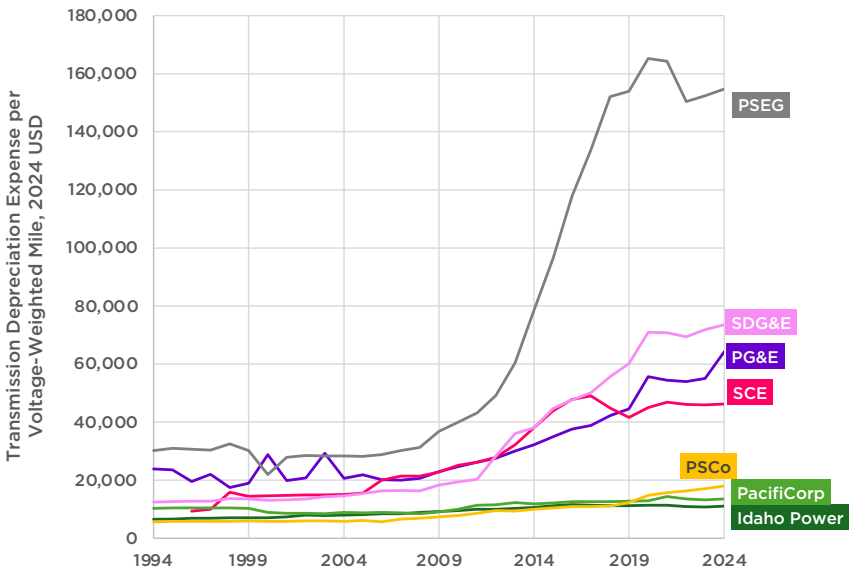


FIGURE 7. *Electric Transmission Revenue Requirement Proxy, Cost per Voltage-Weighted Mile, 2024 USD*

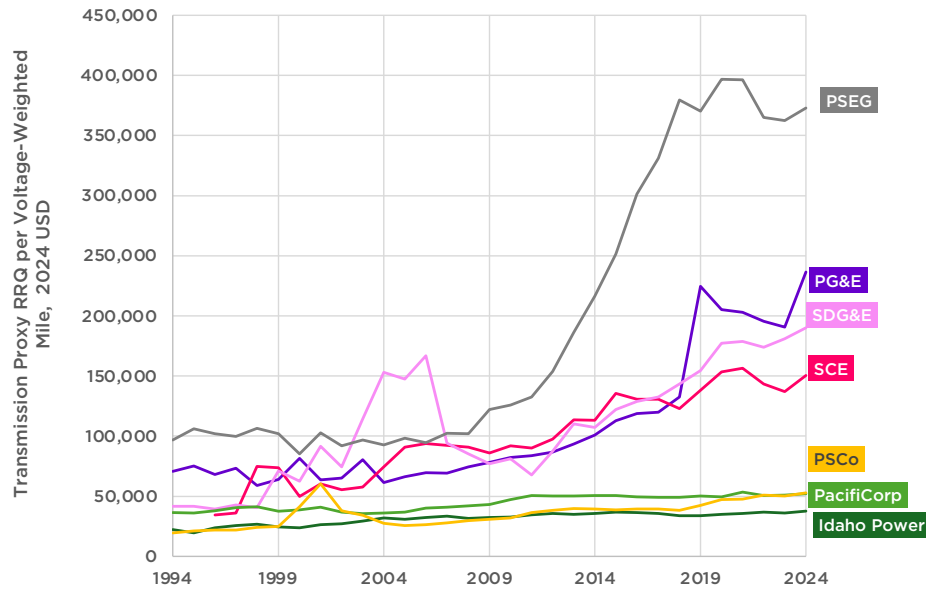
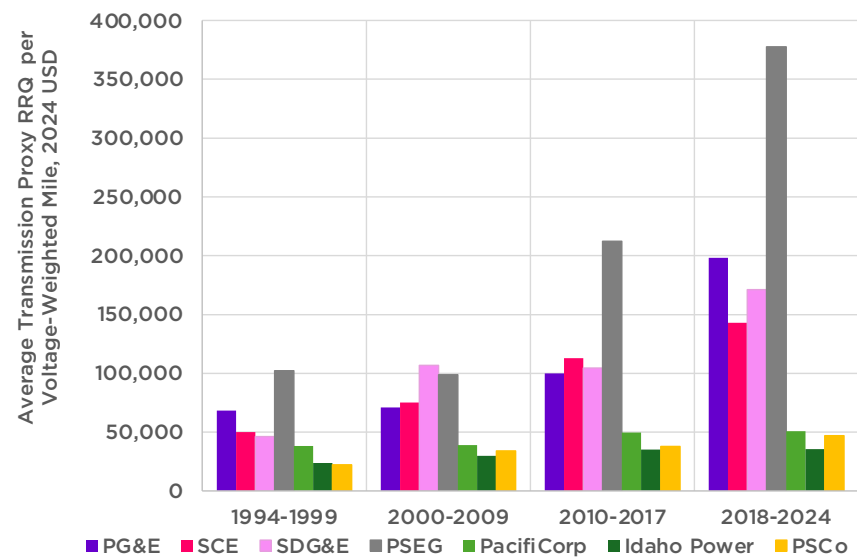


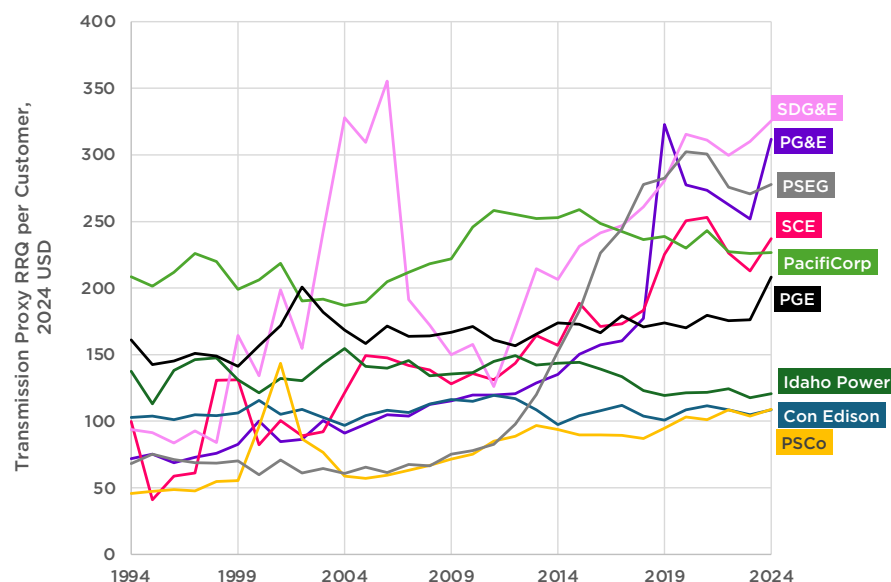
Figure 8 shows annual average transmission revenue requirement proxy values using the same time period grouping we applied to distribution costs. The average values further illustrate that the California IOUs' transmission costs have been at the high end of the peer group since 1994, and have grown more rapidly than other utilities' transmission costs since the '90s, with cost growth accelerating after 2018 in response to wildfires.

FIGURE 8. *Average Annual Electric Transmission Proxy Revenue Requirement, Cost per Voltage-Weighted Mile, 2024 USD*



Given the difficulty constructing a mileage-based benchmarking metric for transmission, and the FERC Form 1 data validation issues we encountered, we also compared annual transmission costs per customer. Figure 9 shows the transmission proxy RRQ cost per customer account for each utility in the peer group; Con Edison and PGE are included in the figure (because the FERC Form 1 data issues for those utilities related to their transmission mileage data, as opposed to their cost data).¹⁶ Using this alternate metric, the California IOUs display a similar trend of transmission cost growth that outpaces their peers.

FIGURE 9. *Transmission Proxy Revenue Requirement Cost per Customer Account, 2024 USD*



CONCLUSIONS AND POTENTIAL NEXT STEPS

This benchmarking exercise reveals an overall trend that across most of the years analyzed, California IOU's unitized distribution and transmission O&M and capex costs are generally higher and increase at a higher rate than other utilities' costs.

The analysis shows the impact of recent wildfire mitigation spending in California on distribution and transmission O&M costs. However, wildfire risk or mountainous terrain does not appear to correlate with higher unitized distribution costs across the full peer group for the time period we analyzed, since several utilities with high fire risk service territories fall at the low end of the cost spectrum (namely, Idaho Power Company, PacificCorp, and Xcel Colorado). Furthermore, the California IOU's cost growth has outpaced the rest of the peer group since before 2018, indicating that wildfire impacts do not explain the full extent of California's high distribution and transmission costs.

¹⁶ Number of customer accounts for each utility are from FERC Form 1 Schedule 304.

Customer population density does seem to have a more consistent relationship with higher costs per mile. Con Edison, PSEG, and Massachusetts Electric all rank toward the top of the peer group in distribution costs, a pattern that may reflect the higher cost of constructing and maintaining underground distribution networks that are more prevalent in dense urban environments. PSEG stands out from the rest of the group for its high unitized transmission costs, which could be related to its high-density urban service territory; PacifiCorp, Idaho Power, and PSCo serve lower-density areas and have the lowest unitized costs of the group for both transmission and distribution.

Labor costs may be another contributing factor: the utilities with the highest unitized costs generally operate in high-wage regions. FERC Form 1 data includes some decomposition of labor costs' contribution to transmission and distribution O&M but does not include a comprehensive disaggregation of labor costs (including capitalized labor) that would be required to directly compare relevant labor costs across utilities.

This analysis represents an initial, high-level comparison based solely on publicly available information. More detailed benchmarking—ideally with direct participation from the IOUs—could help clarify the underlying drivers of California's persistently high unitized T&D costs relative to peer utilities. Some examples of benchmarking data that may be revelatory are:

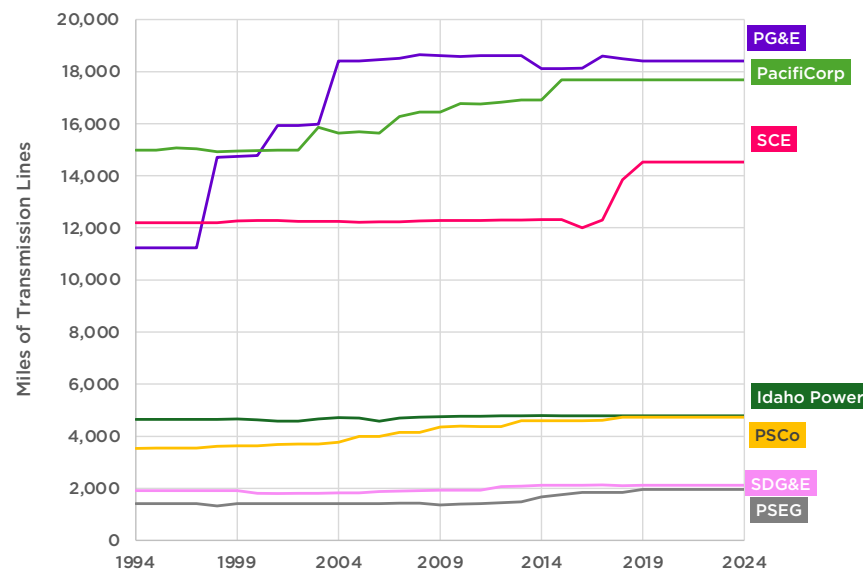
- ▶ Labor cost benchmarking:
 - Wage comparisons, to isolate the effect of potentially higher wages in California relative to other regions
 - Labor efficiency metrics: measures of person-hours required to complete standardized or unitized tasks or projects
 - Quantification of overtime wages paid
 - Quantification of employee versus contractor wages paid
- ▶ Project cost benchmarking:
 - Decomposed cost data for discrete completed T&D projects that can be unitized for direct project-to-project comparison
 - Alternative cost unitization approaches that account for service territory density or other characteristics of T&D infrastructure not captured by cost per mile metrics
 - Decomposed cost and mileage data for overhead and underground transmission and distribution lines, accounting for different cost profiles for undergrounded assets (i.e., higher upfront costs, lower O&M costs)

APPENDIX

Our transmission cost unitization methodology relies on the following assumptions:

UTILITY	LINE-MILE-WEIGHTED AVERAGE TRANSMISSION VOLTAGE (KV)	FERC FORM 1 REPORTING YEAR USED FOR VOLTAGE CALCULATION
Idaho Power Co	166	2024
Pacific Gas & Electric Co.	161	2016
PacifiCorp	180	2009
Public Service Co of Colorado	213	2020
Public Service Elec & Gas Co	251	2019
San Diego Gas & Electric Co	293	2019
Southern California Edison Co	193	2020

Total transmission line miles for each utility are shown in the figure below:



Our methodology for estimating return on rate base from depreciation expense is:

$$\frac{\text{Return on Ratebase}}{\text{Depreciation Expense}} = \frac{\text{WACC} \times \text{Rate Base}}{\text{Depreciation Rate} \times \text{Gross Plant}} = \frac{7\%}{5\%} \times 0.7 \cong 1.0$$

We assume WACC = 7%. We assume average T&D asset book life is 20 years, equivalent to an annual depreciation rate of 5%. Based on recent empirical financial data for the California IOUs, we assume that a typical ratio of net plant to gross plant is 0.7 (where gross plant is the total book value of transmission or distribution assets, and net plant is book value of those assets less accumulated depreciation), and we assume that net plant is a proxy for rate base. Because these are significant assumptions and this is a very roughly generalized rate base calculation, we elected to use the same set of assumptions for each utility, as varying WACC to reflect utility-specific financing costs would give a false sense of precision to the metric.