BENCHMARKING THE COSTS OF ELECTRIC DISTRIBUTION COMPANIES IN NORTH AMERICA

Prepared for

The Connecticut Light and Power Company

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ACRONYMS

A&G	Administrative & General
BEA	US Bureau of Economic Analysis
BLS	US Bureau of Labor Statistics
C&I	Commercial and Industrial
CL&P	The Connecticut Light and Power company
DPU	Department of Public Utilities (MA)
ECI	Employer Cost Index
EDC	Electric Distribution Company
EIA	US Energy Information Administration
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GDP-FSDP	GDP Implicit Deflator for Final Sales to Domestic Purchasers
I-X	Inflation factor minus Productivity factor
LEI	London Economics International LLC
MA	Massachusetts
MW	Megawatt
OHS	One Hoss Shay
OM&A	Operations, maintenance, and administration
PBR	Performance-Based Regulation
PBMRP	PBR Multi-Year Rate Plan
PPI	Producer Price Index
QCEW	Quarterly Census of Employment and Wages
S Factor	Stretch Factor
SAIFI	System Average Interruption Frequency Index
TFP	Total Factor Productivity
U.S.	United States
X Factor	Productivity factor

1 Executive Summary

London Economics International ("LEI") was engaged by Eversource Energy Service Company ("Eversource") on behalf of its operating subsidiary Connecticut Power and Light ("CL&P" or "the Company") to perform a Cost Benchmarking Study to evaluate the Company's efficiency compared to 87 other electric distribution companies ("EDCs" or "utilities") in the United States ("U.S.").[1]

This Cost Benchmarking Study evaluates the performance of an individual EDC by comparing its total costs, including operations, maintenance, and administration ("OM&A") costs, and capital costs, to those of other EDCs in the U.S. There are multiple techniques that could be used for benchmarking. Benchmarking also provides an empirical basis for assessing a utility's relative cost performance and identifying the extent to which additional efficiency improvements may reasonably be achievable over the term of a performance-based regulation ("PBR") plan. While an industry Total Factor Productivity ("TFP") study measures the average productivity improvements across the industry and can inform the X Factor, benchmarking provides a utility-specific assessment of relative efficiency.[2] It serves as a useful input in calibrating the Consumer Dividend (also known as the stretch factor or "S Factor") by helping ensure that any required efficiency improvements are supported by empirical evidence and are appropriately tailored to the utility's circumstances, rather than based solely on industry averages or judgment.

1.1 Overview of the methodology

LEI conducted two distinct, but complementary, forms of cost benchmarking for CL&P: unit cost benchmarking and econometric benchmarking.

Unit cost benchmarking evaluates the ratio of cost to a measure of operating scale, such as total number of customers served, or annual energy (MWh) delivered. It is a mathematically simple technique and can provide high-level comparison of directly observed relative costs of EDCs. This approach is often used in North American utility regulation because of its technical simplicity. Unit cost indexes can be calculated for specific cost categories, such as OM&A costs

[1] Appendix A (Section 5) lists all the utilities included in this Cost Benchmarking Study.

[2] LEI has extensive experience applying benchmarking techniques to evaluate the efficiency and cost performance of electric and natural gas utilities in support of regulatory proceedings, and PBR. Over the past two decades, LEI has advised regulators, utilities, governments, and private-sector clients throughout North America and internationally on matters relating to utility regulation, rate design, productivity analysis, benchmarking, and utility performance measurement. LEI has particular expertise in developing and applying both unit cost and econometric benchmarking methods to assess utility costs, identify efficiency opportunities, and support regulatory decision-making. Appendix B provides examples of LEI's experience in performing benchmarking analyses.

or capital costs, or total cost per customer, and are expressed in real terms to remove the effects of inflation. LEI's unit cost benchmarking is discussed in Section 3.

While informative, unit cost benchmarking does not address critical questions around why a certain EDC may have lower or higher unit costs – for example due to economies of scale or scope, or whether certain business drivers have a material influence over costs, as such as input prices, network configuration and customer mix. LEI therefore also implemented an econometric benchmarking analysis, which estimates a cost function using time-series data for each EDC including representation of key business drivers. The econometric analysis allowed LEI to isolate and investigate the impact of business drivers on costs and measure the relative efficiency of EDCs taking into account such factors. It is important to keep in mind that many of these business drivers can influence costs but are not fully within management's control to change in the short term.

Econometric benchmarking uses statistical models to estimate the relationship between costs and the key factors that contribute to those costs, such as the cost of various inputs that an EDC relies on (such as labor and capital), the scale of operations, network system density, and customer composition. The econometric models quantify the relationship between these business drivers and utility costs, allowing the analysis to measure the relative impact of each factor on OM&A, capital, and total costs. The purpose of this analysis is to compare a utility's actual costs with the costs predicted by the model for a utility with similar business drivers and operating characteristics. By explicitly accounting for differences in these business drivers, the econometric analysis develops a benchmark that more accurately reflects the expected costs of a comparable utility operating under similar conditions. This allows the benchmarking comparison to control for differences across utilities, rather than relying on simple average cost comparisons.

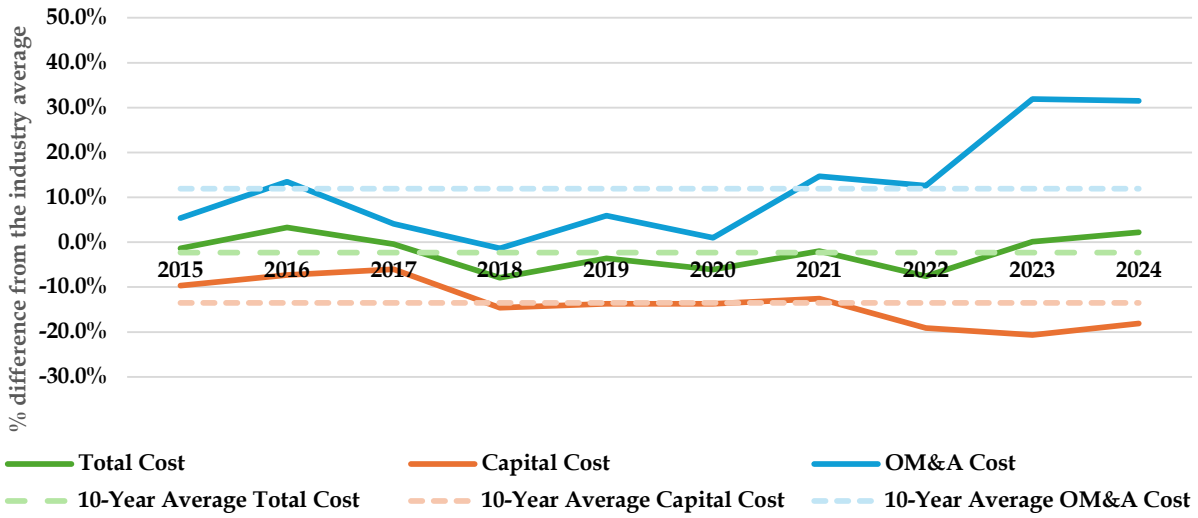
In this study, LEI uses econometric models to estimate the factors that influence OM&A, capital, and total costs. The models estimate how changes in business drivers—such as prevailing labor costs, economies of scale, network density, and customer characteristics—affect utility costs. Once the models are calibrated using actual data for EDCs across the U.S., LEI performs an analysis specifically for CL&P, where model-predicted costs for CL&P are compared against CL&P's actual cost to assess whether CL&P's costs are above or below the benchmark after accounting for relevant cost drivers. Section 4.2 discusses the approach and results of LEI's econometric cost benchmarking.

1.2 Unit Cost benchmarking results indicate that CL&P's historical capital cost and total cost per customer are below the industry average, while OM&A spending is above the industry average

LEI's unit cost benchmarking results indicate that CL&P's cost performance differs across cost categories. As shown in Figure 1, on average over the 2015–2024 period, CL&P's OM&A cost per

customer was approximately **22.9% above** the industry average,[3] while its capital cost per customer was approximately **11.7% below** the industry average. In other words, historically, CL&P used more OM&A cost per customer than the average of its peers and less capital costs per customer than the average of its peers. However, on a total cost per customer, CL&P was approximately **2.6% below** the industry average, indicating that CL&P's overall cost performance was modestly better than the industry average. Section 3.5 discusses the results of LEI's unit cost benchmarking.

Figure 1. CL&P's cost performance relative to industry average based on unit cost benchmarking, 2015–2024 (%)



Note: The reported values represent CL&P's average percentage deviation from the applicable benchmark over the 2015–2024 period. A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark. For the unit cost benchmarking analysis, the benchmark is the industry average unit cost per customer. Dotted lines above are the 10-year averages (2015-2024) for each cost category.

[3] As discussed in Section 3, the industry benchmark in the unit cost benchmarking is the industry average unit cost per customer for the 88 utilities under the national sample.

1.3 After controlling for differences in business drivers, the econometric benchmarking analysis indicates that CL&P's OM&A and capital cost performance is more favorable than suggested by the unit cost benchmarking analysis, while confirming that CL&P's total costs have remained modestly below benchmark

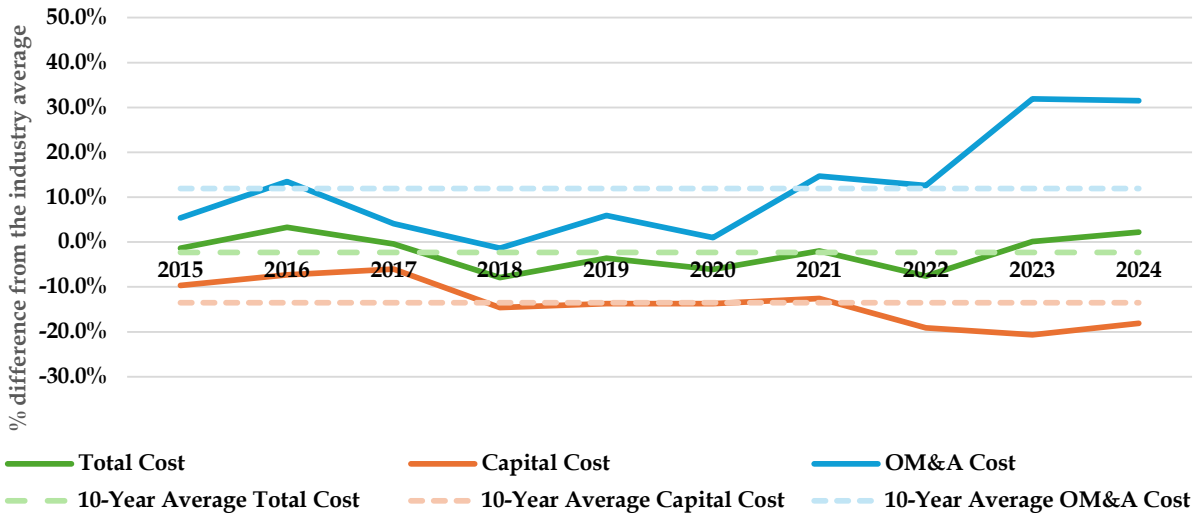
LEI assessed CL&P's cost performance by comparing the Company's actual costs with the costs predicted by econometric models. The model-predicted benchmark represents the expected costs of a typical operating utility with the same observable operating characteristics and business environment as CL&P, including its scale of operations, customer and system characteristics, and prevailing input prices. The benchmarking results are reported as the percentage difference between actual costs and the model-predicted benchmark, with positive values indicating costs above benchmark and negative values indicating costs below benchmark.

Econometric benchmarking results indicate that, after controlling for differences in business characteristics, CL&P's capital costs have consistently remained well below the benchmark, while its total costs have remained modestly below benchmark, as shown in Figure 2. The econometric analysis also indicates that CL&P's relative cost performance with respect to both OM&A and capital costs is more favorable than suggested by the unit cost benchmarking analysis, which compares utilities based solely on average costs per customer without accounting for differences in operating environments and other cost drivers. LEI's econometric benchmarking analysis is based on the same underlying data used in the unit cost benchmarking study but incorporates additional explanatory variables that influence costs in the electric distribution sector, including labor prices, network density, economies of scale, and the proportion of distribution-related operations. By controlling for these business characteristics, the econometric analysis provides a more comprehensive assessment of CL&P's cost performance relative to its peers.

Relative to the model-predicted benchmark,[4] CL&P's OM&A costs averaged approximately **12% above** benchmark over the 2015–2024 period, while its capital costs averaged approximately **14% below** benchmark. On a total cost basis, CL&P's costs averaged about **2% below** the model-predicted benchmark. Section 4.5 discusses the results of LEI's econometric benchmarking.

[4] As discussed in Section 4.3, LEI's econometric approach compares each EDC's actual cost performance against its model-predicted cost performance in each year of the analysis. The model-predicted cost reflects the level of costs that would be expected for an EDC given its specific operating characteristics and cost drivers.

Figure 2. CL&P's cost performance, as compared to from the econometrics-based benchmark, 2015–2024 (%)



Note: The reported values represent CL&P's average percentage deviation from the applicable benchmark over the 2015–2024 period. A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark. For the econometric benchmarking analysis, the benchmark is CL&P's model-predicted cost, estimated using the broader industry sample after controlling for differences in outputs, input prices, and other relevant cost drivers. Dotted lines above are the 10-year averages (2015-2024) for each cost category.

While both benchmarking approaches reach the same overall conclusions regarding CL&P's cost profile, the econometric benchmarking analysis, which provides a more comprehensive assessment of relative cost performance, indicates that CL&P's OM&A costs are closer to the benchmark and its capital costs compare even more favorably with the benchmark than suggested by the unit cost benchmarking analysis, as shown in Figure 3.

Figure 3. CL&P's 10-year average cost performance using the unit cost benchmarking and economic benchmarking

Average, 2015-2024	Unit Cost Benchmarking: CL&P's cost performance relative to Industry Average	Econometric Benchmarking: CL&P's cost performance relative to model predicted Benchmark
Capital costs	-11.7%	-13.5%
OM&A costs	22.9%	11.9%
Total costs	-2.6%	-2.3%

1.4 Inclusion of a 0.30% Consumer Dividend in the Company's PBR Multi-Year Rate Plan ("PBRMP") encourages continued improvements in operating efficiency and falls within the range of Consumer Dividends approved in other jurisdictions

LEI's cost benchmarking analysis indicates that CL&P's overall cost performance compares favorably with that of its peer electric distribution utilities. Over the study period, CL&P's total costs generally remained below the levels predicted by the econometric benchmarking model, reflecting particularly strong performance with respect to capital-related costs. At the same time, CL&P's OM&A costs averaged above benchmark, indicating that opportunities remain for continued operating efficiency improvements. Because the Company's proposed revenue adjustment mechanism applies only to OM&A costs, these results provide empirical support for including a modest Consumer Dividend that encourages continued improvements in operating efficiency while recognizing the Company's strong overall cost performance.

Benchmarking alone does not determine the appropriate annual Consumer Dividend, as it identifies relative efficiency at a given point in time, rather than the pace at which company-specific productivity improvements can reasonably be achieved year-over-year during a PBR term. Accordingly, LEI also reviewed the Consumer Dividends approved by other North American regulators. First, these precedents demonstrate that regulators implementing PBR frameworks consider utility-specific benchmarking results in the process of setting an appropriate Consumer Dividend. Second, the case study analysis shows that approved Consumer Dividends (or stretch factors) range from 0.15% to 0.60%. It is also important to keep in mind that the stretch factor should be set with some consideration to the overall X Factor. In other words, the Consumer Dividend should not overwhelm the overall productivity target. Given CL&P's historical performance and its proposed X Factor, LEI recommends a 0.30% Consumer Dividend for CL&P's PBMRP, which falls within the observed range from other jurisdictions with revenue cap frameworks, such as Alberta, British Columbia, Massachusetts, and Ontario, as discussed in Section 0.

2 The purpose of Cost Benchmarking

Statistical benchmarking is a quantitative approach to performance measurement that uses data on utility operations to compare an individual firm's costs and efficiency against those of peer utilities. The objective is to estimate a utility's relative efficiency, that is, whether its costs are higher or lower than would be expected relative to similarly situated utilities after accounting for legitimate differences in the conditions under which they operate. The two benchmarking methods most used in utility regulation are unit cost benchmarking, which compares normalized cost metrics across utilities, and econometric benchmarking, which statistically estimates the relationship between costs and the factors that influence those costs. [5]

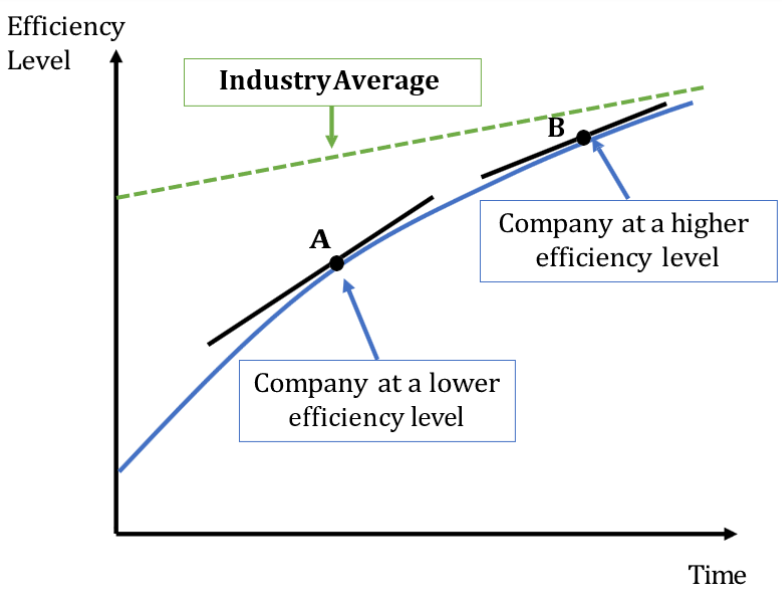
Unlike productivity studies, which measure how the industry has improved over time, benchmarking is achieved through a cross-sectional assessment of a utility's performance relative to its peers at a particular point in time. It therefore answers a different, but complementary, question. Whereas an industry TFP study measures the industry's long-run rate of productivity growth,[6] benchmarking evaluates whether an individual utility is currently operating above, below, or near the industry's expected cost pattern.

Benchmarking results provide empirical evidence that regulators use to inform their expectations for a utility's future efficiency improvements to "catch up" to the overall industry trajectory of efficiency improvements over time. A utility found to be less efficient than its peers might reasonably be expected to improve faster than the industry average, since it may have more low-hanging fruit for cost reduction, such as opportunities to adopt better technologies or management practices that more efficient peers have already captured. Conversely, a utility that is already relatively efficient generally has fewer remaining opportunities for additional cost reductions beyond the industry's ongoing productivity improvements. This concept is commonly referred to as the convergence effect; whereby less efficient firms are expected to improve more rapidly than firms that are already operating near the efficient frontier. Figure 4 below provides a simplified illustration of this concept. The firm at position A begins at a lower level of relative efficiency than the firm at position B and, consequently, has greater potential to improve its performance over time by closing part of the gap (as indicated by the larger slope of the black line at its position – the slope represents the change in efficiency levels over time).

[5] Lowry, Mark Newton, and Lullit Getachew. "Statistical Benchmarking in Utility Regulation: Role, Standards and Methods." *Energy Policy*, vol. 37, no. 4, Apr. 2009, pp. 1323–1330. https://doi.org/10.1016/j.enpol.2008.11.027.

[6] LEI's TFP Industry Study is discussed in Exhibit CLP-PBR-2.

Figure 4. Illustration of the convergence effect



Note: The pace of improvement over time for an individual firm is not a straight line but a curved line. This is because the convergence effect slows the improvement of efficiency over time. The black lines tangent to the blue curve represents the slope, or rate of change of efficiency over time, at position A (with represents a firm at a lower efficiency level) and position B (which represents a firm at a higher efficiency level).

PBR is intended to strengthen utilities' incentives to control costs and improve efficiency compared to traditional cost-of-service regulations. Under a typical revenue cap or price cap plan, allowed revenues or prices are updated annually using an I–X adjustment mechanism, where I represents an inflation measure and X represents an expected rate of productivity improvement. The X Factor generally consists of two distinct components. The first is the industry productivity factor, which reflects the long-run rate of productivity growth achieved by the industry as a whole relative to the broader economy. The second is a utility-specific Consumer Dividend or S Factor, which represents any additional productivity improvements that regulators determine a particular utility should reasonably be able to achieve based on its relative efficiency compared to peer utilities.

LEI's two studies are designed to inform these complementary components of CL&P's proposed PBR framework. LEI's Industry TFP Study estimates the industry-wide productivity trend that informs the productivity component of the X Factor. The Cost Benchmarking Study, by contrast, evaluates CL&P's current level of cost efficiency relative to comparable EDCs across the U.S. The purpose of this benchmarking analysis is to determine whether CL&P appears to have meaningful opportunities to improve its efficiency relative to its peers and, if so, to provide

empirical evidence that may assist the Authority in evaluating whether a utility-specific Consumer Dividend is appropriate and, if appropriate, the magnitude of that factor.

3 Unit cost benchmarking

For purposes of this study, the Cost Benchmarking Study evaluates three cost components: OM&A costs, capital-related costs, and total costs, where total costs are defined as the sum of OM&A and capital-related costs. Unit cost benchmarking compares utilities based on the ratio of cost to a measure of operating scale, such as the number of customers served, to provide a straightforward, high-level view of relative cost performance across EDCs, where a lower unit cost rank indicates a lower total cost per customer. LEI calculates unit cost benchmarks for OM&A and capital cost separately, as well as for total cost, using real (inflation-adjusted) dollar values so that comparisons across utilities and overtime are not distorted by inflation.

3.1 Data sources used

LEI used the same dataset of capital costs, OM&A costs, customer counts, sales and inflation measures that were used in the LEI Industry TFP Study; which are primarily sourced from Federal Energy Regulatory Commission ("FERC") Form 1. LEI also relied on data from the US Bureau of Economic Analysis ("BEA"), the BLS, the Energy Information Administration ("EIA"), the Federal Reserve Economic Data ("FRED"), Moody's, Institute of Taxation and Economic Policy, U.S. Department of the Treasury, S&P Capital IQ, and the Internal Revenue Service. Accordingly, the Unit Cost Benchmarking analysis is based on the same sample of utilities as the TFP study, comprising 88 EDCs in the national sample, which cover approximately 90% of customers served by investor-owned utilities in the U.S.

3.2 LEI's unit cost benchmarking approach

The data for the unit cost benchmarking comes entirely from LEI's TFP study. LEI uses annual OM&A costs that have been deflated into real dollar terms, as well as annual capital costs (also reported in real dollar terms), and total customers served each year (which was the output metric in LEI's Industry TFP Study). OM&A costs for each utility and year is calculated as the sum of five categories of Electric Operation and Maintenance Expenses reported in FERC Form 1: (i) Total Distribution Expenses, (ii) Total Customer Accounts Expenses, (iii) Total Customer Service and Informational Expenses, (iv) Total Sales Expenses, and (v) a portion of the Total Administrative & General ("A&G") Expense.[7]

LEI excluded FERC Account 908 (Customer Assistance Expenses) from both the unit cost and econometric benchmarking analyses because the objective of these studies is to evaluate the

[7] Because A&G expenses are incurred at the company level and support functions beyond electric distribution, LEI includes only the portion of A&G expenses attributable to distribution operations, calculated by proportioning total company A&G expenses based on the utility's electric distribution plant in service as a share of its total plant in service.

efficiency of electric distribution utilities in providing distribution service. Account 908 primarily consists of expenditures for customer assistance and public policy programs—such as energy efficiency, demand-side management, low-income assistance, and customer education—that are largely driven by legislative and regulatory requirements rather than the efficiency with which a utility plans, operates, and maintains its distribution system. These expenditures also vary considerably across jurisdictions based on differences in state policy objectives. In the unit cost benchmarking analysis, including Account 908 could distort direct cost comparisons by attributing policy-driven expenditures to differences in utility efficiency. In the econometric benchmarking analysis, while the model controls for many legitimate cost drivers, it generally cannot fully account for variation in state-specific public policy mandates, creating a risk that policy-driven expenditures would be interpreted as inefficiency. Excluding Account 908 therefore improves the comparability of utilities and focuses both benchmarking approaches on costs that are more directly associated with the provision of electric distribution service.

OM&A costs include labor and non-labor costs and are deflated into real dollar terms using an Employment Cost Index ("ECI") and Gross Domestic Product Implicit Deflator for Final Sales to Domestic Purchasers ("GDP-FSDP").[8] These two indexes are combined using each utility's labor cost share in a given year, which reflects the proportion of OM&A cost attributable to labor relative to non-labor inputs.

Labor expense is calculated as the sum of Distribution of Salaries and Wages reported in FERC Form 1 for the same five functional categories used to define OM&A cost: Distribution, Customer Accounts, Customer Service and Informational, Sales, and a portion of the A&G expenses. Non-labor expenses represented the other costs reported in these five functional categories.

Capital costs are based on the estimated annual capital service flow, which measures the annual productive use of capital assets expressed in constant 1988 dollars. It is calculated by multiplying the real capital stock by the capital price, where the capital price represents the annual cost of using that capital in a given year; in simple terms, this converts the stock of capital into an annual measure of capital services being consumed by each EDC, as described in greater detail in LEI's Industry TFP Study.[9]

3.3 Unit cost benchmarking results

At the national level, CL&P ranks 47th out of 88 utilities on total cost per customer over the 2005–2024 period, placing it near the midpoint of the national EDC sample. Disaggregating total costs

[8] For the base year normalization, LEI uses 1988, as it corresponds to the start year of the Industry TFP Study.

[9] *See* Exhibit CLP-PBR-2.

by category reveals a more nuanced picture: CL&P ranks more favorably on capital cost per customer, at 32nd out of 88, but less favorably on OM&A cost per customer, at 69th out of 88.

When comparing CL&P specifically to its Northeast Region[11] peers, CL&P's relative ranking improves: it ranks 8th out of 22 utilities in the Northeast Region on total cost per customer and capital cost per customer, placing it in the first quartile of the Northeast Region peers for those costs. With respect to OM&A costs per customer, CL&P ranks 11th out of 22 in the Northeast Region, at the median mark in the regional peer group for the region. Taken together, these results indicate that over the past 10 years, CL&P's total cost performance has tracked close to the industry average nationally, while its capital and total cost rankings stand out as comparatively strong within the Northeast Region, CL&P is observed to have higher OM&A spending than have the regional peers and a majority of national peers. Figure 5 presents the results of LEI's unit cost benchmarking analysis for CL&P, based on the 10-year average ranking of real OM&A cost, capital cost, and total cost per customer over the 2005-2024 period.

Figure 5. CL&P's average ranking nationally and in the Northeast Region

Costs/Years & Region	10-year average ranking (2015–2024) Nationally — out of 88 utilities	10-year average ranking (2015–2024) Northeast region — out of 22 utilities
OM&A Cost/Customer	69	11
Capital Cost/Customer	32	8
Total Cost/Customer	47	8

Note: A lower rank number (E.g., 1st) reflect lower costs (and stronger relative performance) among the peer group while higher rank numbers reflect progressively higher costs relative to peers.

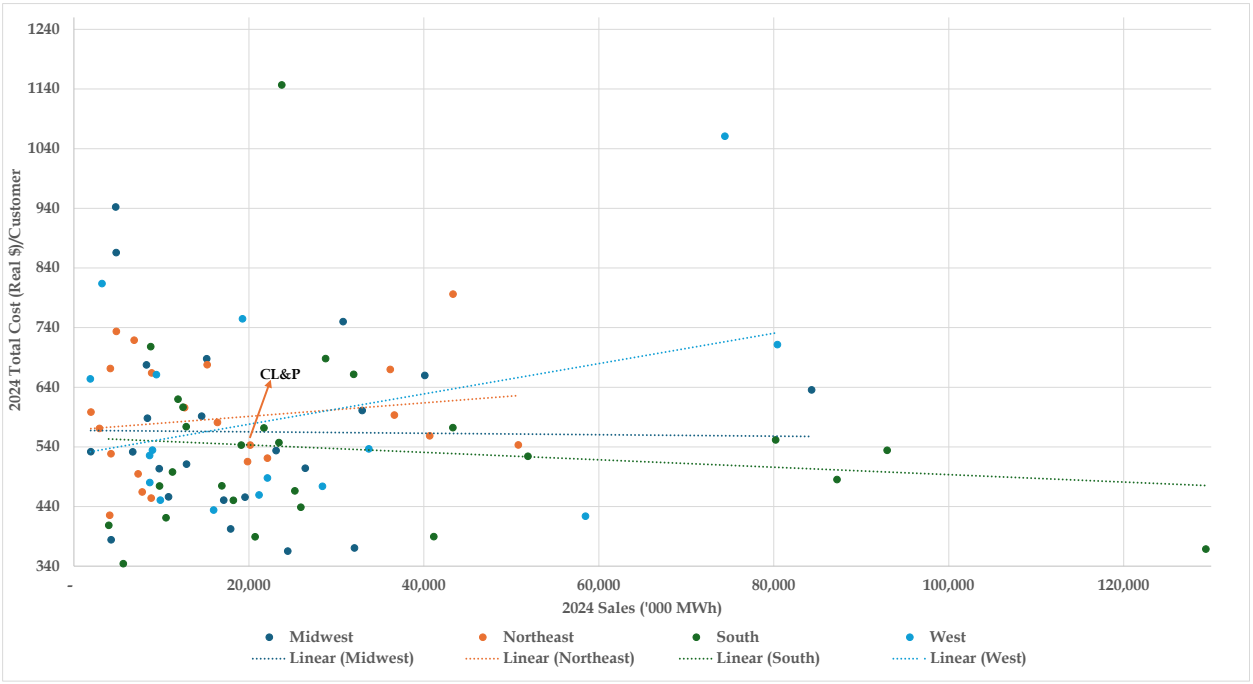
3.4 Other observations from unit cost benchmarking

This section builds on the unit cost benchmarking results above by examining how total cost per customer trends with utility scale, network density, and share of distribution business, providing context for CL&P's ranking and informing the econometric analysis in Section 3.5.

Figure 6 illustrates the relationship between total cost per customer and utility scale, measured using 2024 electricity sales volume, and speaks to the potential presence of economies of scale in

utility costs.[10] The chart reveals differing scale dynamics across regions: the relationship among EDCs in West and Northeast Regions presents a clear upward-sloping trend, consistent with economies of scale, where larger utilities tend to achieve lower total cost per customer than smaller ones. By contrast, South and Midwest regions show comparatively flat to downward sloping trendlines, indicating that total cost per customer for EDCs in these regions does not present strong economies of scale patterns. This suggests that the relationship between scale and cost efficiency is not uniform across the country, and that business drivers are interacting with scale of EDC operations to effect costs.

Figure 6. Total costs per customer vs. sales, 2024



CL&P, as a midsized Northeast Region utility with 2024 sales of approxiamtely20.2 million MWh and a 2024 total cost of approximately $543 per customer, falls slightly below the Northeast Region trendline, suggesting that it achieves costs that are at or somewhat better than expected for a utility of its size relative to its Northeast Region peers.

Figure 7 illustrates the relationship between total cost per customer and network density, measured using 2024 customers per circuit. A higher density of customers allows for fixed costs

[10] LEI used sales as a proxy for scale. Number of customers could also have been used, but since customers are already reflected in the unit costs, LEI used sales to further differentiate the variables.

of each circuit to be spread over more customers, lowering the total cost per customer. Network density can be an indicator for whether the system is serving an urban area or a rural area. A utility typically has limited control over whether it is serving urban or rural customer base, or the type of customer mix it serves. The chart reveals differing relationships between network density and cost across regions. EDCs in the South exhibit a clear downward-sloping trend, with utilities serving more customers per circuit generally reporting lower total cost per customer. The Midwest trendline is broadly flat to slightly downward-sloping, indicating only a weak relationship between network density and cost per customer. By contrast, the Northeast and West Regions show modest upward-sloping trends. Overall, the relationship between network density and cost efficiency is not uniform across regions, suggesting that other business, geographic, and operating characteristics may interact with circuit density to influence costs.

Figure 7. Total costs per customer vs. network density (customers per circuit), 2024

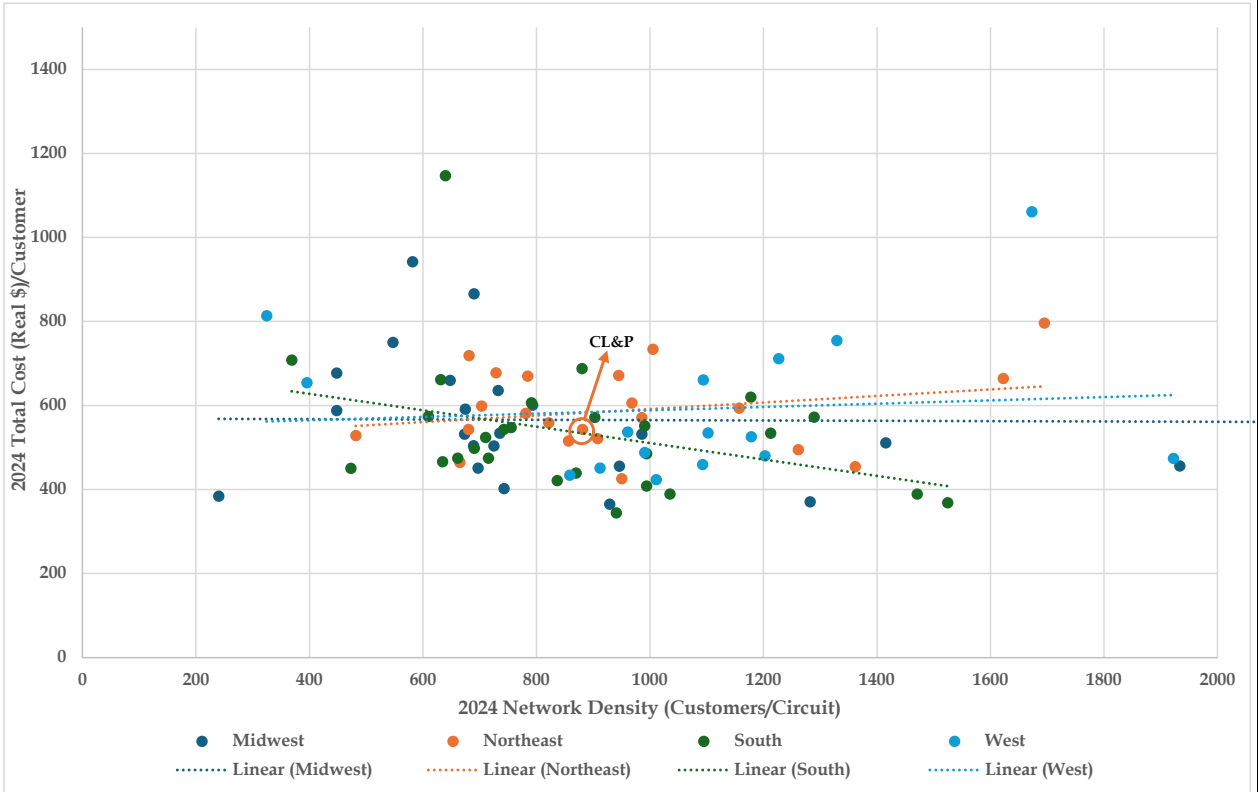
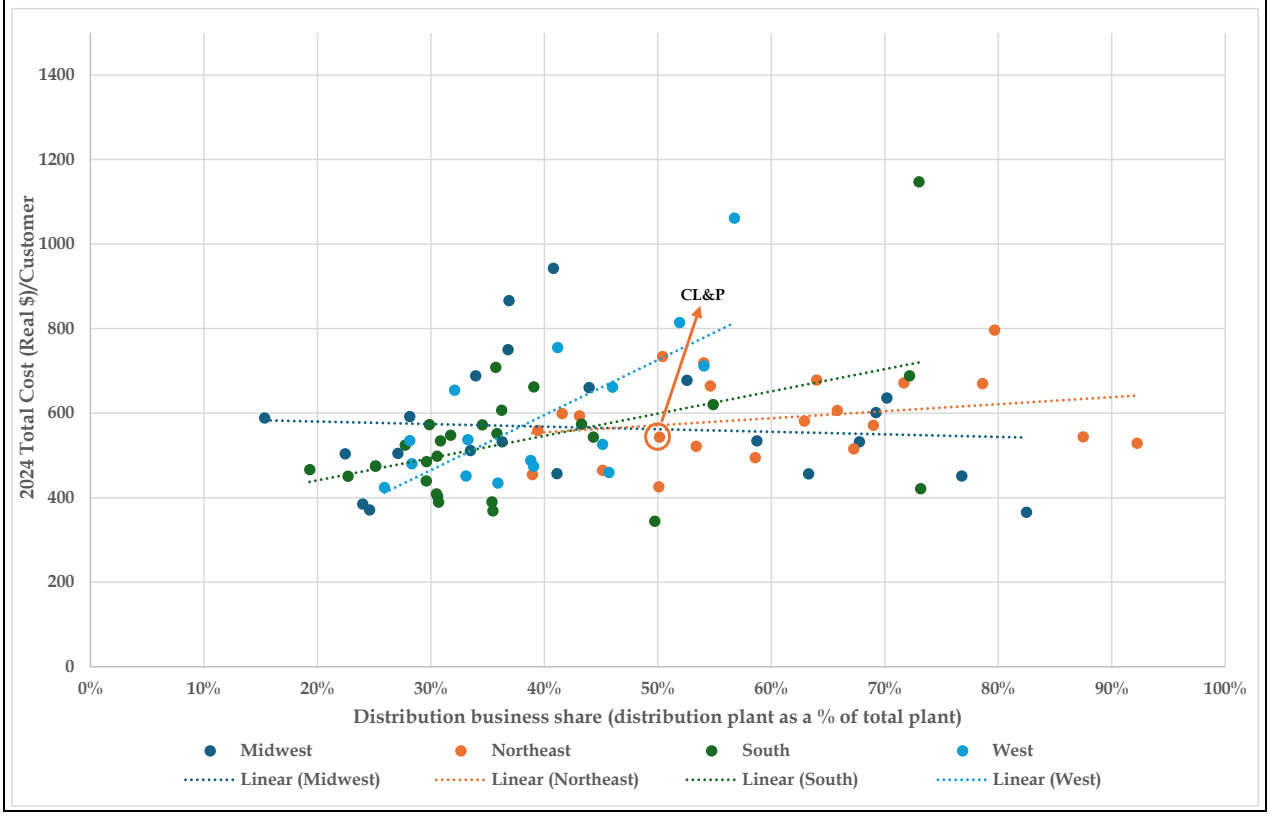


Figure 8 illustrates the relationship between total cost per customer and distribution business share for each EDC as of 2024; distribution business share is measured as distribution plant as a percentage of total plant. Many, but not all, EDCs also own transmission assets and therefore have a transmission utility business. Some of the utilities in the national sample also have a regulated generation business. Economies of scope may be present for utilities that have

extensive associated businesses, which gives them an opportunity to allocate certain fixed costs (for example, certain administrative costs) over more business functions. Intuitively, a lower distribution share should mean lower total cost per customer. This pattern holds among EDCs in the Northeast, South, and West Regions, each showing an upward-sloping trend, where utilities with a greater distribution share tend to carry higher total cost per customer. The Midwest is the exception: its trendline is flat to slightly downward-sloping, suggesting distribution share is not a meaningful cost driver for utilities in that region. CL&P sits at roughly a 50% distribution share with a total cost per customer of $543 in 2024, modestly below its regional (Northeast) trendline, indicating its costs are somewhat lower than what a comparable Northeast utility would be expected to have at that distribution share.

These business drivers of cost are further explored through econometric benchmarking in Section 4.4.

Figure 8. Total costs per customer vs. distribution business share of utility, 2024



3.5 CL&P cost performance in comparison to industry average

LEI also examined the unit costs of CL&P relative to the industry. Over the 10-year period, CL&P's OM&A costs, capital costs, and total costs per customer averaged $148, $285, and $432, respectively. The U.S. industry average for this same period was $120, $326, and $446, respectively for OM&A, capital, and total costs per customer.

CL&P's OM&A costs generally exceeded the industry average, while its capital costs have consistently remained below the industry average as presented in Figure 9. CL&P's total cost performance relative to the industry average has improved over recent years: the 4-year average is **5.6% below** industry average versus the ten years, which is **2.6% below** the industry average. This indicates that CL&P's above-average OM&A costs and below-average capital costs have largely offset one another relative to industry peers, keeping its overall total cost performance close to, and modestly better than, industry average throughout the period.

Figure 9. CL&P's actual unit costs relative to industry average by cost component, 2015–2024, % (graph)

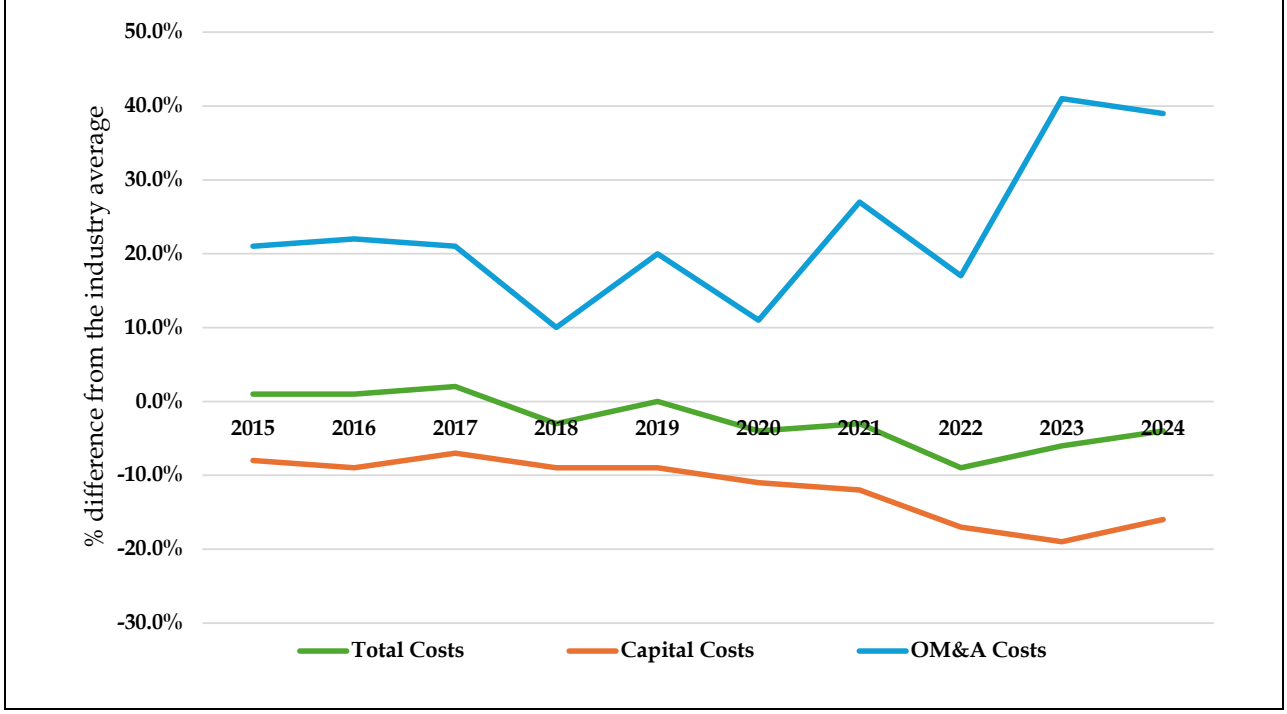


Figure 10. CL&P's actual unit costs relative to industry average by cost component, 2015–2024, % (table)

Year	Total Cost	Capital Cost	OM&A Cost
2015	1.0%	-8.0%	21.0%
2016	1.0%	-9.0%	22.0%
2017	2.0%	-7.0%	21.0%
2018	-3.0%	-9.0%	10.0%
2019	0.0%	-9.0%	20.0%
2020	-4.0%	-11.0%	11.0%
2021	-3.0%	-12.0%	27.0%
2022	-9.0%	-17.0%	17.0%
2023	-6.0%	-19.0%	41.0%
2024	-4.0%	-16.0%	39.0%
10-year average	**-2.6%**	**-11.7%**	**22.9%**
4-year average	**-5.6%**	**-15.9%**	**31.0%**

Note: A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark.

4 Econometric cost benchmarking

4.1 Overview of econometric techniques

Cost benchmarking analysis can also be conducted using econometric methods. In LEI's professional judgement, if the data allows, an econometric benchmarking analysis is preferable to the unit cost benchmarking approach. This is because unit cost benchmarking, as detailed in Section 3, typically compares utility costs by dividing expenditures such as OM&A, capital, or total costs by a single output measure such as the number of customers served (or the volume of electricity sales). While useful as a high-level indicator, this approach can be overly simplistic as it does not account for the numerous other factors that may influence an EDC's costs. These factors may include among others, input prices such as the cost of labor and capital, the customer density of the EDC's service territory, the composition of its customer base (proportion of residential versus commercial and industrial customers), and various other operating/business conditions which may differ across EDCs, but are not necessarily under the EDC management's control. Furthermore, the unit cost benchmarking does not explain why an EDC may exhibit higher or lower unit costs. For example, differences in unit costs may reflect economies of scale or scope, or variations in business drivers that materially influence costs, such as input prices, network configuration, and customer mix.

Econometric benchmarking provides a more comprehensive approach by estimating the statistical relationship between a dependent variable, such as total cost, capital cost or OM&A cost, and one or more independent, or explanatory variables that are expected to influence those costs. These explanatory variables may also be referred to as business drivers. By controlling for these types of business drivers, econometric analysis can help isolate the relationship between utility costs and factors that influence costs and may be outside, or only partially within, management's control. This allows for a more meaningful assessment of relative cost performance than a unit cost comparison alone. In particular, econometric cost benchmarking analysis can provide an estimate of relative efficiency after accounting for differences in operating conditions and important business factors across U.S. EDCs, thus ensuring a more accurate and informed benchmarking analysis.

The econometric approach to cost benchmarking relies on calculating the average (or "mean") value for a feature such as number of customers and comparing how an individual observation in the data (for example, a particular EDC in a single year) compares to the average size of all the EDCs across all the years in the data. Econometric analysis then tests for correlations across such differences in means. For example, it tests whether the difference from the mean number of customers is correlated with the difference from the mean total cost expenditures for an EDC.

Econometrics-based benchmarking is a well-established approach for comparing utilities based on their expenditures, outputs, and operating conditions. It has been used or relied upon in

regulatory proceedings and benchmarking frameworks in several jurisdictions, including the United States, Canada, Australia, New Zealand, and the United Kingdom.[11]

4.2 LEI's econometrics benchmarking approach

As with the unit cost benchmarking, LEI developed three econometric cost benchmarking models: an OM&A cost model, a Capital cost model, and a Total Cost model, using most of the data from the LEI Industry TFP Study.

LEI performed the econometric benchmarking analysis using actual (historical) data from a sample of 88 EDCs, including CL&P, to estimate the average relationship between costs and factors that impact or otherwise contribute to those costs. Such a relationship is also known as a cost function. LEI used 10 years of data (2015-2024), resulting in a balanced panel dataset with 880 total observations. A panel dataset means that a sample group of EDCs is observed across multiple years. This structure enables examination of differences in costs across EDCs, while also capturing how costs and cost drivers change over time. A *balanced* panel means that each EDC in the sample is observed in each year of the study period. In other words, there are no missing utility-year observations in the final dataset, allowing for a consistent comparison of cost performance across utilities and over time.

LEI's choice of 10 years of data strikes an appropriate balance between two competing objectives: 10 years provides enough data points to support a statistically robust analysis given the need to test various business drivers (econometric models benefit from having a sufficiently large number of observations, as this improves the precision and reliability of the statistical estimates), while also capturing a range of historical operating conditions to ensure continued relevance to inform future rate setting in a PBR context, while also.

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[11] *See* Ontario Energy Board. *Performance Assessment.* accessed July 6, 2026 https://www.oeb.ca/ontarios-energy-sector/performance-assessment; Ontario Energy Board, *PEG Benchmarking Report 2024* (Toronto: Ontario Energy Board, 2024) <https://www.oeb.ca/sites/default/files/PEG%20Report%20to%20the%20Ontario%20Energy%20Board%202024.pdf> ; Australian Energy Regulator. *Annual Benchmarking Report – Distribution and Transmission 2025*. (Melbourne: Australian Energy Regulator, 2025), https://www.aer.gov.au/publications/reports/performance/annual-benchmarking-report-distribution-and-transmission-2025; Office of Gas and Electricity Markets (Ofgem). *RIIO-ED2 Final Determinations: Core Methodology*. (London: Ofgem, November 2022) https://www.ofgem.gov.uk/sites/default/files/2022-11/RIIO-ED2%20Final%20Determinations%20Core%20Methodology.pdf; Michael G. Pollitt. *Benchmarking and Optimal Scale for Electricity Distribution Boards in New Zealand: A Study for the Commerce Commission*. (Wellington: New Zealand Commerce Commission, 2025), https://comcom.govt.nz/assets/Documents/productivity-and-efficiency-study-of-electricity-distributors/Michael-Pollitt-Benchmarking-and-Optimal-Scale-for-Electricity-Distribution-Boards-in-New-Zealand-A-study-for-the-Commerce-Commission-20-November-2025.pdf

In addition to estimating how each business driver affects annual costs (expenditures) by EDCs in the U.S. on average, including both the magnitude and direction of that relationship, LEI's econometric approach also allows for a comparison of an EDC's actual cost performance against its model-predicted cost performance in each year of the analysis. As detailed in Sections 4.6 and 4.7, the annual model-predicted costs reflect the level of annual costs that would be expected for an EDC given its specific operating characteristics and business drivers. Comparing actual costs to model-predicted costs therefore provides an indication of relative cost performance after controlling for differences in business conditions, developed on the basis of cross-sectional data representing the U.S. EDC sector.

4.3 Data sources used

LEI developed the econometric benchmarking dataset using cost data from LEI's Industry TFP study and explanatory variables that control for key cost drivers for EDCs. Section 4.4 discusses the variables used in the econometric benchmarking and their respective results in the preferred specifications. The econometric models use utility-year observations and are designed to explain differences in OM&A cost, capital cost, and total cost across utilities and over time.

The cost variables are constructed on a nominal basis using FERC Form 1 data. Nominal total cost is calculated as the sum of nominal OM&A cost and nominal capital cost.[12] Each cost variable is transformed into natural logarithmic form so that the model can compare proportional differences in costs across utilities of different sizes.

The explanatory variables were selected to control for the price of key inputs (like market-prevailing wages and capital price index (to reflect generic inflationary pressures on capital)), differences in scale (using customers as proxy), network density (in terms of customers served per circuit), economies of scope (related to size of distribution business to total utility business), and time. These factors are expected to affect cost levels and therefore need to be controlled for before comparing CL&P's actual costs to model-predicted costs.

The variables used in the econometric models are summarized in Figure 11 and described in further detail below.

[12] LEI uses nominal cost measures because the econometric models include input price variables to control for differences in cost conditions across utilities and over time. Labor price is controlled for using state-level average annual pay, while capital price is controlled for using a capital price index based on the Bureau of Labor Statistics PPI in the capital and total cost models. Therefore, the dependent variables are kept in nominal terms so that the model benchmarks actual reported costs, while the explanatory variables separately account for input price differences.

Figure 11. Overview of the variables used in LEI's models

Dependent variable	Independent variable	Type of variable or transformation
OM&A cost		natural log
	Labor price	natural log
	Customers	natural log
	Distribution business share	-
	Time trend	-

Dependent variable	Independent variable	Type of variable or transformation
Total Cost		natural log
	Labor price	natural log
	Capital price index	-
	Customers	natural log
	$(\text{Customers})^2$	squared natural log
	Network density	-
	Distribution business share	-
	Time trend	-

Dependent variable	Independent variable	Type of variable or transformation
Capital Cost		natural log
	Customers	natural log
	$(\text{Customers})^2$	squared natural log
	Network density	-
	Labor price	natural log
	Capital price index	-
	Distribution business share	-
	Time trend	-

The three **dependent** variables included in LEI's models were OM&A cost, capital cost, and total cost as described below:

- **OM&A cost:** OM&A cost is one of the dependent variables in the benchmarking analysis. It reflects annual operations, maintenance, and administrative costs associated with electric distribution utility operations. OM&A cost is sourced from FERC Form 1[13] and constructed consistently with LEI's TFP cost methodology. It is transformed into natural logarithmic form (similar to all the other variables) which allows the model to compare proportional cost differences across utilities and years.

[13] Federal Energy Regulatory Commission. *FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others*. Federal Energy Regulatory Commission, <www.ferc.gov/general-information-0/electric-industry-forms>

- **Capital cost:** Capital cost is another dependent variable in the benchmarking analysis. It reflects the annual capital cost measure developed in LEI's TFP cost model. Capital cost captures the cost associated with the use of capital assets in providing electric distribution service. This variable is sourced from FERC Form 1 and constructed consistently with LEI's TFP cost methodology.

- **Total cost:** Total cost is the third dependent variable in the benchmarking analysis. It is calculated as the sum of nominal OM&A cost and nominal capital cost. This variable captures the combined cost of operating, maintaining, and investing in the distribution system.

LEI tested several **independent** variables in our models. These include labor price, capital price, customer scale, network density, share of distribution assets to total assets, and time trends:

Input prices:

- **Labor price:** Labor price is measured using state-level utility industry average annual pay. LEI relied on the BLS Quarterly Census of Employment and Wages ("QCEW").[14] as the source for state-level wage data. This variable is used as a proxy for labor input prices and controls for differences in labor costs across states and years. Because labor costs vary across states and regions, utilities operating in higher-wage labor markets are generally expected to incur higher OM&A and total costs than otherwise comparable utilities operating in lower-wage labor markets, all else equal.

- **Capital price index:** Capital price is measured using a capital price index based on the BLS Power Price Index ("PPI").[15] This variable is used as a proxy for capital input prices. It controls for changes in the cost of capital-related inputs over time. The capital price index is included in the capital cost and total cost models because these models include capital-related costs as part of the dependent variable.

Other input variables:

- **Customer scale:** Customer counts are used as the primary scale variable. LEI relied on customer count data from EIA Form 861.[16] The number of customers served provides a

[14] U.S. Bureau of Labor Statistics. *Quarterly Census of Employment and Wages*. U.S. BLS, <www.bls.gov/cew/>

[15] U.S. Bureau of Labor Statistics. *Producer Price Indexes*. <www.bls.gov/ppi/>

[16] U.S. Energy Information Administration. *Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files*. Electricity Data. <www.eia.gov/electricity/data/eia861/>

measure of the scale of each EDC's distribution operations. All else equal, utilities serving more customers would be expected to incur higher total costs because they must construct, operate, and maintain larger distribution systems and provide service to a greater number of customer connections. In the capital cost and total cost models, LEI also included the square of logged customers to allow for potential non-linear scale effects. This allows the relationship between scale and cost to differ between smaller and larger utilities, rather than imposing a strictly linear relationship.

- **Network density:** Network density is measured using customers per circuit and is an important determinant of distribution costs. Distribution circuit information is sourced from EIA Form 861 and used to calculate the number of customers served per circuit. It controls for differences in the density of the distribution network. Network density also serves as an indicator of whether a utility primarily serves an urban or a rural service territory. All else equal, a utility serving more customers per circuit can spread fixed costs over a larger customer base. Conversely, a utility serving fewer customers per circuit typically requires more infrastructure relative to the number of customers served. As a result, utilities operating less densely populated distribution systems may face higher costs of providing distribution service. Because utilities generally have limited control over the geographic characteristics of their service territories, customer density, and customer mix, controlling for these business characteristics helps ensure that benchmarking comparisons reflect differences in cost performance rather than differences in operating environment.

- **Share of distribution business:** Distribution plant share is measured as distribution plant as a share of total plant. This variable is calculated using FERC Form 1 plant data. It is used as a proxy for the extent to which a utility's overall business is focused on distribution activities. Many, but not all, electric distribution utilities also own transmission assets and therefore operate a transmission business. Some utilities in the national sample also own regulated generation assets. Utilities with a broader mix of regulated business activities may benefit from economies of scope by spreading certain fixed costs—such as administrative and corporate support costs—across multiple business functions. Consequently, a utility with a lower distribution plant share (i.e., a greater proportion of non-distribution activities) would generally be expected to have lower distribution costs per customer, all else equal. Including this variable helps control for differences in business scope and better isolate differences in distribution-related cost performance..

- **Time trend:** LEI included an annual time trend covering 2015–2024. This variable is included as trend. The time trend captures residual cost changes over time that are not otherwise explained by scale, network density, input prices, customer mix, or distribution business share. Such changes may reflect common industry-wide trends, technology changes, changes in reporting, or other time-related effects.

LEI tested several other independent variables, but they were ultimately excluded as they were found not to be statistically significant for the study timeframe and group of utilities.[17]

4.4 Overview of econometric models

LEI's econometric results show that the preferred cost models provide strong explanatory power and that the estimated coefficients are generally consistent with economic intuition. The OM&A, capital, and total cost models each have independent variables (representing business drivers) that explain a substantial share of the variation in utility costs across the 88 EDCs in the sample over the 2015–2024 period. The following findings summarize the main results from the preferred specifications and Appendix C show the total cost, capital, and OM&A cost economic results in table format. [18]

- **Labor prices are a major factor impacting costs, and in elasticity (percentage) terms, the largest marginal driver for OM&A.** The coefficient is positive and statistically significant in all three models. In the OM&A model, the coefficient is 0.973 with a p-value of 0.000. The coefficient value reflects the marginal impact of market prevailing wages on OM&A costs – for every 10% change in wages, OM&A costs go up 9.73%. The p-value of 0.000 signifies that this finding is statistically significant with a 99.9% confidence level. In the total cost model, the coefficient is 0.618 with a p-value of 0.000. The lower coefficient in the total cost model relative to the OM&A model is not surprising given that other inputs, whose prices may not be correlated with labor prices, are part of total cost. In the capital cost model, the coefficient is 0.397 with a p-value of 0.000. The result is consistent with the more limited impact of labor on capital costs. Overall, these results indicate that utilities operating in higher-wage states tend to have higher expected costs, all else equal.

- **Capital price index has a statistically significant impact on the capital and total costs.** In the total cost model, the coefficient is 0.250 with a p-value of 0.000. In the capital cost model, the coefficient is 0.427 with a p-value of 0.000. These results indicate that higher capital input

[17] LEI tested additional explanatory variables before selecting the preferred specifications. The share of non-residential customers was calculated as commercial and industrial customers divided by total customers, and was tested as a customer-mix variable but not retained because it was not statistically significant. Customer density was calculated as total customers divided by distribution circuits. Non-linear customer scale was constructed as the square of the natural logarithm of total customers. This non-linear customer scale term was retained in the total cost and capital cost models, but not in the OM&A model. Capital price variables were included in the total cost and capital cost models and were also tested in the OM&A model, but were not retained in the OM&A specification because they did not materially improve model fit.

[18] *See* Section 7.

prices are associated with higher expected capital-related costs, consistent with economic intuition.

- **Operating scale as measured by number of customers has an impact on OM&A cost**. In the OM&A model, the coefficient for the natural log of the number of customers is 0.870 and is statistically significant, which means that with every 10% increase in customers, OM&A costs increase by 8.7%. The p-value indicates that we are 99.9% confident in these findings. This result is consistent with economic intuition: utilities serving more customers generally require more operating, maintenance, and administrative resources.

- **The total cost and capital cost models allow for non-linear operating scale effects, which may capture more nuanced impacts of operating scale across utilities of different sizes.** LEI's total cost and capital cost models include two variables for scale: natural log of Customers and natural log of Customers squared, which allows the relationship between customer scale and cost to be non-linear. This specification does not assume that the cost impact of customer scale is the same for all utilities. Instead, it allows the relationship between scale and cost to change as utilities become larger. A negative sign on the non-linear variable will capture the situation where costs increase less than proportionally with size. In the total cost model, the coefficient on Customers is -0.185 with a p-value of 0.424 (which means that this linear scale variable is not statistically significant at a conventional 95% confidence level), while the coefficient on Customers squared is 0.042 with a p-value of 0.000. In the capital cost model, the coefficient on Customers is -0.052 with a p-value of 0.836 (again, this means that this linear scale variable is not statistically significant at a conventional 95% confidence level), while the coefficient on Customers squared is 0.040 with a p-value of 0.000. The significance of the squared customer term indicates that the relationship between customer scale and cost is not strictly linear. The customer scale variables should therefore be interpreted jointly rather than separately. In simple terms, the models allow the cost impact of customer scale to vary between smaller and larger utilities, rather than assuming that a 1% increase in customers has the same proportional impact for every utility in the sample. For CL&P, given its 2024 customer count of approximately 1.29 million, a 10% increase in its customers is associated with approximately a 10.0% increase in total cost and a 10.7% increase in capital cost.

- **Network density has a negative relationship with capital cost.** Network density is measured as customers per circuit. In the capital cost model, the coefficient is approximately -0.000053 with a p-value of 0.044, indicating that customer density is statistically significant at the 95% confidence level and that a 100% increase in network density reduces capital costs by 0.0053%. The negative sign suggests that, all else equal, utilities with more customers per circuit tend to have lower expected capital costs, which is consistent with the idea that denser systems can spread network infrastructure costs over more customers. Because capital costs are part of total costs, LEI also included network density as an explanatory variable in the total cost

model. In the total cost model, the coefficient is approximately -0.000012 with a p-value of 0.566, meaning it is intuitive in the directional impact, but not statistically significant.

- **Distribution business share is positively associated with expected costs and controls for differences in business scope.** In practical terms, this variable measures how much of a utility's overall plant in service is related to distribution. A lower value means that a utility has extensive non-distribution business functions because it has a larger share of plant in service associated with other utility functions, which would allow it to allocate some of its fixed costs to other business function and reduce distribution-related costs. The coefficient is positive across all three models consistent with the intuition. In the OM&A model, the coefficient is 0.516 with a p-value of 0.000, which means that for every 10% increase in distribution plant share, OM&A costs increase 5.16%. In the total cost model, the coefficient is 0.309 with a p-value of 0.000. In the capital cost model, the coefficient is 0.045 with a p-value of 0.459. These results indicate that utilities with a larger distribution share of total plant tend to have higher expected distribution-related costs, all else equal. This is consistent with the variable's role as a proxy for the extent to which a utility's business is focused on distribution activity.

- **The time trend is not statistically significant in the total and capital cost models at a 95% confidence level.** In the OM&A model, the coefficient on trend is -0.0067 with a p-value of 0.160, meaning the effect is negative but not statistically significant at conventional levels. In the total cost model, the coefficient on trend is approximately 0.0021 with a p-value of 0.767. In the capital cost model, the coefficient on trend is approximately 0.0095 with a p-value of 0.259. These results indicate that the time trend does not have a statistically significant independent effect on the OM&A, total cost, or capital cost models after controlling for the other cost drivers. One likely reason is that the models include input price variables, including labor price and, for the total and capital cost models, the capital price index, which capture part of the time-related movement in input costs.

- **All three cost models have strong overall fit.** The total cost model has an R-squared of approximately 0.948, indicating that the model explains about 94.8% of the variation in total cost across the sample. The capital cost model has an R-squared of approximately 0.932, explaining about 93.2% of the variation in capital cost. The OM&A model has an R-squared of approximately 0.887 and an adjusted R-squared of approximately 0.887, indicating that the model explains about 88.7% of the variation in OM&A cost.

Overall, the econometric results support the use of these models for benchmarking. The models have strong explanatory power, estimated coefficient signs that are generally consistent with economic intuition, and the fitted values that provide a reasonable estimate of expected costs for each utility-year observation. These fitted values are then used to compare CL&P's actual costs against model-predicted costs, both annually and over multi-year averages, to assess CL&P's relative cost performance.

4.5 CL&P's cost performance in comparison to the predicted model

LEI assessed CL&P's cost performance by comparing CL&P's actual costs with the fitted values predicted by the econometric models. This comparison was performed on a year-by-year basis for each model. The benchmarking result is calculated as the percentage difference between actual cost and model-predicted cost:

Benchmarking result = (Actual cost / Predicted cost - 1) × 100%

A **positive** benchmarking result means that CL&P's actual cost is **above** the model-predicted benchmark. A **negative** benchmarking result means that CL&P's actual cost is **below** the model-predicted benchmark.

The year-by-year comparison provides an annual measure of CL&P's relative cost performance after controlling for key cost drivers. In other words, the benchmarking result does not simply compare CL&P's costs to the average utility in the sample. Instead, it compares CL&P's actual costs to the level of costs the model predicts for a utility with CL&P's characteristics, including its customer scale, input price environment, distribution business share, and other relevant cost drivers.

LEI also calculated average benchmarking results over the full 2015–2024 period and over the most recent four-year period (2021-2024). The ten-year average provides a long-term view of CL&P's cost performance, while the four-year average places greater weight on recent cost levels and trends. Showing these two averages helps identify whether CL&P's cost performance is persistent over time or concentrated in particular years.

Over the 10-year period (2015–2024), CL&P's total costs were modestly below the model-predicted benchmark, averaging approximately **2.3% below** benchmark over the ten-year period, as shown in Figure 13. This overall result reflects offsetting trends across cost categories: capital costs were consistently favorable, averaging approximately **13.5% below** benchmark, while OM&A costs remained above benchmark, averaging approximately **11.9% above** benchmark. Over the ten-year period, capital costs generally remained below benchmark throughout, helping to keep total costs below benchmark overall. In contrast, OM&A benchmarking results worsened over time, meaning CL&P's OM&A costs moved further above the model-predicted benchmark in later years. As a result, CL&P's total cost performance remained modestly favorable on average, but the trend suggests that OM&A has become the primary source of increasing cost pressure. Figure 12 shows the results for the 10-year period.

Figure 12. CL&P's cost performance compared to the model-predicted benchmark (2015-2024), % (graph)

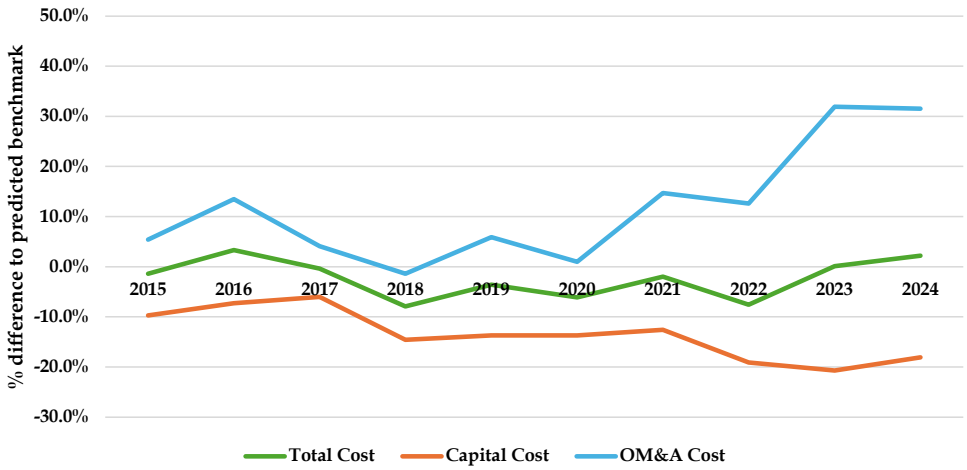


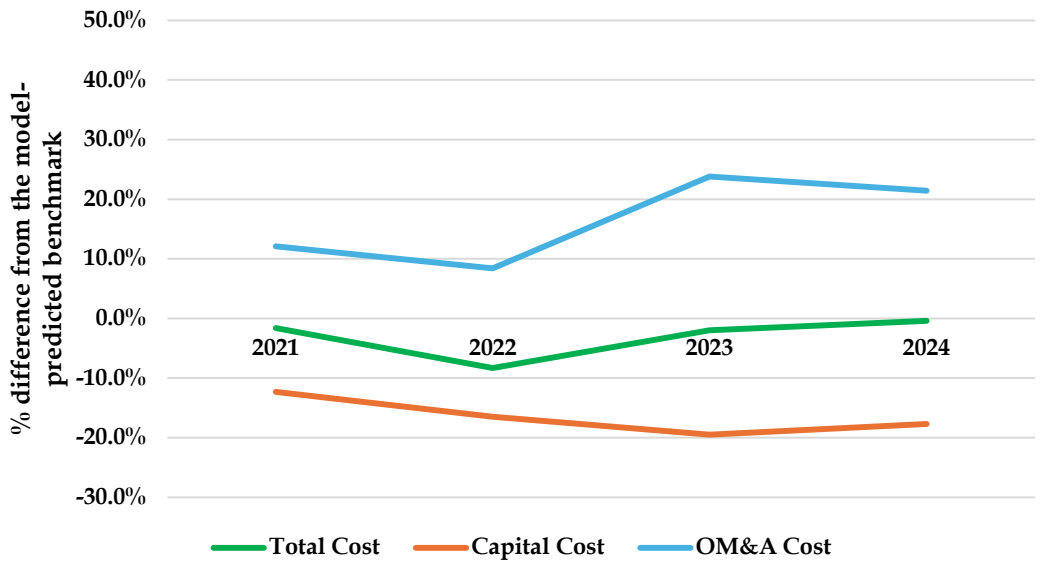
Figure 13. CL&P's cost performance compared to the model-predicted benchmark (2015-2024), % (table)

Year	Total Cost	Capital Cost	OM&A Cost
2015	-1.4%	-9.7%	5.4%
2016	3.3%	-7.3%	13.5%
2017	-0.4%	-6.0%	4.1%
2018	-7.9%	-14.6%	-1.4%
2019	-3.6%	-13.7%	5.9%
2020	-6.1%	-13.7%	1.0%
2021	-2.0%	-12.6%	14.7%
2022	-7.6%	-19.1%	12.6%
2023	0.1%	-20.7%	31.9%
2024	2.2%	-18.1%	31.5%
10-year average	**-2.3%**	**-13.5%**	**11.9%**

Note :The reported values represent CL&P's average percentage deviation from the applicable benchmark over the 2015–2024 period. The 10-year model was estimated using the full ten-year historical dataset. A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark.

The most recent four-year period (2021-2024) shows a similar pattern [19] but with more pronounced divergence between capital and OM&A cost performance. Over 2021–2024, CL&P's total costs averaged approximately **3.1% below** benchmark, which is better than the 10-year average result. Capital costs were even further below benchmark in the recent period, averaging approximately **16.5% below** benchmark, indicating that capital cost performance remained favorable. However, OM&A costs were also further above benchmark, averaging approximately **16.4% above** benchmark over the same four-year period. This indicates that recent total cost performance remained modestly favorable primarily because below-benchmark capital costs continued to offset increasingly above-benchmark OM&A costs. Figure 14 and Figure 15 present the results for the 4-year period.

Figure 14. CL&P's cost performance compared to the model-predicted benchmark (2021-2024), % (graph)



[19] The 4-year model was estimated separately using only the four most recent years of data from that same dataset, allowing the results to reflect cost relationships observed over the more recent period of analysis.

Figure 15. CL&P's cost performance compared to the model-predicted benchmark (2021-2024), % (table)

Year	Total Cost	Capital Cost	OM&A Cost
2021	-1.6%	-12.3%	12.1%
2022	-8.3%	-16.5%	8.4%
2023	-2.0%	-19.5%	23.8%
2024	-0.4%	-17.7%	21.4%
4-year average	**-3.1%**	**-16.5%**	**16.4%**

Note: The reported values represent CL&P's average percentage deviation from the applicable benchmark over the 2021-2024 period. The 4-year model was estimated separately using only the four most recent years of data from that same dataset, allowing the results to reflect cost relationships observed over the more recent period of analysis. A positive value indicates that CL&P's costs are above the benchmark, while a negative value indicates that CL&P's costs are below the benchmark. Accordingly, negative values indicate relatively more favorable cost performance, as they reflect lower costs than the benchmark.

Overall, the benchmarking results are consistent across both the ten-year and four-year averaging periods. In both cases, CL&P's capital costs and total costs remain below the model-predicted benchmark, indicating favorable overall cost performance relative to comparable electric distribution companies after controlling for differences in operating characteristics. At the same time, OM&A costs remain above benchmark and have increased in the more recent period, suggesting that opportunities for additional operating efficiencies continue to exist.

The consistency of these findings across both the long-term and recent analyses provides confidence that the observed cost patterns are not driven by isolated years but instead reflect sustained trends in CL&P's cost performance.

5 Conclusion

LEI's Cost Benchmarking Study provides empirical evidence regarding CL&P's relative cost performance and, as such, serves as one input in assessing the reasonableness of the proposed Consumer Dividend under the Company's proposed PBMRP. However, benchmarking results should not be interpreted as a direct measure of the annual productivity improvements that can reasonably be expected under a PBR framework. Rather, the benchmarking reflects long-run differences in relative cost performance that may arise from structural, operational, geographic, and other utility-specific characteristics, many of which cannot reasonably be eliminated over a single PBR term. Accordingly, benchmarking identifies relative efficiency and the potential for further improvement, but it does not, by itself, estimate the annual rate at which additional productivity gains can be achieved.

As discussed in the preceding section, LEI's benchmarking analysis indicates that CL&P's total costs have generally remained below the benchmark level predicted by the econometric model over the study period, reflecting particularly strong performance with respect to capital-related costs. At the same time, CL&P's OM&A costs have, on average, exceeded benchmark levels, indicating that opportunities remain for additional operating efficiency improvements. While CL&P's OM&A costs remain above the industry average and the benchmark under the unit cost and econometric benchmarking analyses, respectively, these findings should not be interpreted as evidence of widespread operational inefficiency. Instead, they indicate that CL&P's cost structure has historically been characterized by a greater reliance on OM&A expenditures, and a correspondingly lower reliance on capital-related expenditures, relative to its peer utilities.

These findings are particularly relevant because the Company's proposed RAM applies only to OM&A costs. Accordingly, the OM&A benchmarking results provide empirical support for the inclusion of a modest Consumer Dividend that recognizes the potential for continued improvements in operating efficiency while acknowledging the Company's strong overall cost performance. The Company's proposed Consumer Dividend of 0.30% is, in LEI's opinion, reasonable in light of these benchmarking results.

Furthermore, the experience of other North American regulatory commissions provides useful insights and point of comparison. These jurisdictions, specifically Alberta, Massachusetts and Ontario, demonstrate that regulators implementing PBR frameworks consider utility-specific benchmarking results in determining an appropriate Consumer Dividends. In addition, Commissions have also considered the overall design of the proposed PBR framework and its components[20] in determining the Consumer Dividends. For example, the Alberta Utilities

[20] For example, in the Unitil rate case (MA Docket DPU-23-80/DPU 23-81), the MA Department of Public Utilities states, "Given the other components of the PBR mechanisms approved in this proceeding, the Department concludes that a consumer dividend of 25 basis points represents an appropriate explicit, tangible ratepayer benefit." [Source: Massachusetts Department of Public Utilities. *Petitions of Fitchburg Gas and Electric Light*

Commission stated, "PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes)." This recognizes that the Consumer Dividend should complement, not dominate, the overall productivity target established under the PBR framework.

The results indicate that the approved Consumer Dividends generally range from 0.15% to 0.60%, as shown in Figure 16 below. CL&P's proposed Consumer Dividend of 0.30% falls comfortably within this range and is consistent with the moderate stretch factors approved by commissions in jurisdictions such as Alberta, British Columbia, Massachusetts, and Ontario.[21]

*Company d/b/a Unitil (Electric Division) and Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division) for Approval of General Increases in Base Distribution Rates and Performance-Based Ratemaking Plan*s. D.P.U. 23-80 and D.P.U. 23-81. Final Order. June 28, 2024. P. 43.]. Also, in the National Grid rate case, the Commission states this "In the sections above and below, Department approves an X factor of 0.21 percent, a five-year stay-out provision, and an ESM. Based on these considerations, the Department rejects the Attorney General's recommended consumer dividend of 50 basis points." [Source: Massachusetts Department of Public Utilities. *Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of a General Increase in Base Distribution Rates for Electric Service, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism.* D.P.U. 23-150. Final Order. September 30, 2024. P. 88.]

[21] For the Ontario Energy Board's 2025 benchmarking update, electricity distributors were assigned to one of five efficiency cohorts for purposes of determining their stretch factors. Of the 54 distributors evaluated, 17 were assigned to Cohort I, 15 to Cohort II, 17 to Cohort III, 3 to Cohort IV, and 2 to Cohort V. Thus, approximately 91% of Ontario's electricity distributors were assigned to the three most favorable cohorts, corresponding to stretch factors ranging from 0.00% to 0.30%, while only five distributors were assigned to the two least favorable cohorts with stretch factors of 0.45% and 0.60%. [Source: Pacific Economics Group Research LLC. *Empirical Research in Support of Incentive Rate-Setting: 2024 Benchmarking Update*, report prepared for the Ontario Energy Board (Toronto, ON: Ontario Energy Board, August 18, 2025). Table 5, "Stretch Factor Assignments by Group." < https://www.oeb.ca/sites/default/files/PEG%20Report%20to%20the%20Ontario%20Energy%20Board%202025_20250818.PDF>]

Figure 16. Sample of approved S Factor from other jurisdictions

Jurisdiction and EDC	Approved S Factor / Consumer Dividend	Term	Source
Alberta (ATCO Electric Ltd.; FortisAlberta Inc.; ENMAX Power Corp.; EPCOR Distribution & Transmission Inc.; ATCO Gas and Pipelines Ltd.; and Apex Utilities Inc.)	0.1% = Industry TFP + stretch factor 0.30% = "benefit-sharing premium" (X Factor premium)	2024-2028	Alberta Utilities Commission, *2024–2028 Performance-Based Regulation Plan for Alberta Electric and Gas Distribution Utilities* , Decision 27388-D01-2023, Proceeding 27388 (October 4, 2023)
British Columbia — FortisBC Inc.	0.25% Stretch Factor	2025-2027	British Columbia Utilities Commission, *FortisBC Energy Inc. and FortisBC Inc. 2025 to 2027 Rate Setting Framework* , Orders G-69-25 and G-70-25 (March 18, 2025)
Massachusetts — Massachusetts Electric Company and Nantucket Electric Company	0.40% Consumer Dividend (applicable only when inflation is at least 2%; 0.20% when inflation is between 1% and 2%; and 0% when inflation is 1% or lower.	2020-2024	Massachusetts Department of Public Utilities, *Petition of Massachusetts Electric Company and Nantucket Electric Company for Approval of General Increases in Base Distribution Rates for Electric Service* , D.P.U. 18-150 (September 30, 2019)
Massachusetts — NSTAR Electric Company	0.25% Consumer Dividend (applicable only when inflation exceeds 2%)	2023-2027	Massachusetts Department of Public Utilities, *Petition of NSTAR Electric Company for Approval of a General Increase in Base Distribution Rates and a Performance Based Ratemaking Plan* , D.P.U. 22-22 (November 30, 2022)
Massachusetts — Fitchburg Gas and Electric Light Company	0.25% Consumer Dividend (applicable only when inflation exceeds 2%)	2024-2029	Massachusetts Department of Public Utilities, *Petitions of Fitchburg Gas and Electric Light Company for Approval of General Increases in Base Distribution Rates and Performance-Based Ratemaking Plans* , D.P.U. 23-80 and D.P.U. 23-81 (June 28, 2024)
Massachusetts — Massachusetts Electric Company and Nantucket Electric Company	0.40% (applicable only when the composite inflation index exceeds 2%)	2024-2029	Massachusetts Department of Public Utilities, *Petition of Massachusetts Electric Company and Nantucket Electric Company for Approval of a General Increase in Base Distribution Rates, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism* , D.P.U. 23-150 (September 30, 2024)
New Hampshire — Public Service Company of New Hampshire d/b/a Eversource Energy	0.15% (applicable only when GDP-PI inflation exceeds 2%)	2026-2029	New Hampshire Public Utilities Commission, *Public Service Company of New Hampshire d/b/a Eversource Energy – Request for Change in Distribution Rates: Order Establishing Permanent Rates and Alternative Regulation Through July 31, 2029* , Order No. 28,170, Docket DE 24-070 (July 25, 2025)
Ontario - All utilities	Based on benchmarking performance and ranges between 0.00% and 0.60%		Ontario Energy Board. *2025 PEG Benchmarking Report to the Ontario Energy Board* . Prepared by Pacific Economics Group LLC. August 18, 2025

6 Appendix A: List of EDCs included in the Industry TFP and Benchmarking Study

Midwest

1. AES Indiana
2. Ameren Illinois Company
3. Commonwealth Edison Company
4. Consumers Energy Company
5. DTE Electric Company
6. Duke Energy Indiana, LLC
7. Duke Energy Ohio, Inc.
8. Evergy Kansas South, Inc.
9. Evergy Metro, Inc.
10. Indiana Michigan Power Company
11. MDU Resources Group, Inc.
12. Minnesota Power Enterprises, Inc.
13. Northern Indiana Public Service Company, LLC
14. Northern States Power Company - MN
15. Northern States Power Company - WI
16. Ohio Edison Company
17. Southern Indiana Gas and Electric Company
18. The Cleveland Electric Illuminating Company
19. The Dayton Power and Light Company
20. The Empire District Electric Company
21. Union Electric Company
22. Wisconsin Electric Power Company
23. Wisconsin Public Service Corporation

Northeast

24. The Connecticut Light and Power Company
25. Atlantic City Electric Company
26. Central Hudson Gas & Electric Corporation
27. Central Maine Power Company
28. Consolidated Edison Company of New York, Inc.
29. Duquesne Light Company
30. FirstEnergy Pennsylvania Electric Company
31. Green Mountain Power Corporation
32. Jersey Central Power & Light Company
33. Massachusetts Electric Company
34. New York State Electric & Gas Corporation

35. Niagara Mohawk Power Corporation
36. NSTAR Electric Company
37. Orange and Rockland Utilities, Inc.
38. PECO Energy Company
39. PPL Electric Utilities Corporation
40. Public Service Company of New Hampshire
41. Public Service Electric and Gas Company
42. Rochester Gas and Electric Corporation
43. The Narragansett Electric Company
44. The United Illuminating Company
45. Versant Power

South

46. Alabama Power Company
47. Appalachian Power Company
48. Baltimore Gas and Electric Company
49. Cleco Power LLC
50. Delmarva Power & Light Company
51. Dominion Energy South Carolina, Inc.
52. Duke Energy Carolinas, LLC
53. Duke Energy Florida, LLC
54. Duke Energy Kentucky, Inc.
55. Duke Energy Progress, LLC
56. Entergy Arkansas, LLC
57. Entergy Mississippi, LLC
58. Entergy New Orleans, LLC
59. Florida Power & Light Company
60. Georgia Power Company
61. Kentucky Utilities Company
62. Louisville Gas and Electric Company
63. Mississippi Power Company
64. Monongahela Power Company
65. Oklahoma Gas and Electric Company
66. Potomac Electric Power Company
67. Public Service Company of Oklahoma
68. Southwestern Electric Power Company
69. Southwestern Public Service Company
70. Tampa Electric Company
71. The Potomac Edison Company
72. Virginia Electric and Power Company

West

73. Arizona Public Service Company
74. Avista Corporation
75. Black Hills Power, Inc.
76. El Paso Electric Company
77. Idaho Power Company
78. Nevada Power Company
79. Pacific Gas and Electric Company
80. PacifiCorp
81. Portland General Electric Company
82. Public Service Company of Colorado
83. Public Service Company of New Mexico
84. Puget Sound Energy, Inc.
85. San Diego Gas & Electric Company
86. Sierra Pacific Power Company
87. Southern California Edison Company
88. Tucson Electric Power Company

7 Appendix B: LEI team's qualification for the Cost Benchmarking Study

LEI has advised on rate design and regulation in the natural gas and electricity industries, for both public and private clients worldwide and has extensive knowledge of the natural gas and electricity sector in New England. Moreover, LEI has performed a broad range of regulatory services for various utilities around the world, including providing regulatory support pertaining to rate cases, TFP studies, benchmarking, and design of service quality indicators over the last two decades. LEI team's project experience related to performing benchmarking studies include:

- ***Prepared a presentation regarding benchmarking in the distribution business:*** In this instance, LEI was retained by an industry advocacy group in the electricity industry to provide a presentation on the benchmarking regimes in the electricity industry, which included theory, application, and case studies.

- ***Performed corporate costs benchmarking for Ontario Power Generation ("OPG"):*** LEI performed an independent benchmarking assessment of OPG's corporate support costs. In addition to the independent benchmarking analysis, LEI supported OPG through the rate application process, in the preparation of evidence, and provision of expert testimony, supporting OPG in attaining its reasonable costs for the provision of corporate support services.

- ***Performed a benchmarking analysis for a major Australian investment bank:*** LEI was retained by a major Australian Investment bank to research embedded costs for electric distribution companies, which included benchmark analysis for Emera, Hydro One, and National Grid.

- ***Corporate costs benchmarking:*** LEI performed an independent benchmarking assessment of a large Canadian generator's corporate support costs. In addition to the independent benchmarking analysis, supported the utility through its rate application process, in particular in the preparation of evidence, and provision of expert testimony, supporting it in attaining its reasonable costs for the provision of corporate support services.

- ***Proposed a benchmarking method to arrive at a reasonable return margin for the Regulated Rate Option service providers:*** LEI provided an expert opinion regarding an appropriate return margin for the Regulated Rate Option service providers ("RSP"), which was filed with the Alberta Utilities Commission as evidence in the proceeding to review the RSPs' current energy price-setting plans ("EPSP"). LEI concluded that a reasonable return margin could be established using a benchmarking method and that competitive electricity retailers in Alberta were the most

appropriate peer set against which to benchmark RRO returns. LEI recommended a comprehensive return margin, expressed in $/MWh, calculated using the average competitive retailer markup as a base and adjusting for customer acquisition costs.

- ***Utilizing benchmarking analysis for the cost of capital and capital structure analysis***: LEI advised Jordan's power regulator on the weighted average cost of capital and optimal capital structure for the country's three distribution companies: EDCO, IDECO, and JEPCO. LEI's work included identifying salient risk factors for the distribution companies, identifying appropriate local and international metrics and benchmarks, developing a usable cost of the capital model, and providing training workshops for local staff. The recommended optimal capital structure was consistent with targeted debt service and interest coverage ratios in line with the rating methodology for distribution companies from the global credit rating agencies.

8 Appendix C: Summary of econometric results (2015-2024)

The econometric models are estimated using a balanced panel of 88 EDCs over the 2015–2024 period, for a total of 880 utility-year observations. The dataset includes cost variables for OM&A, capital, and total cost, as well as explanatory variables that control for customer scale, network density, labor price, capital price, distribution business share, and time. Robust standard errors were used to address potential heteroskedasticity, and alternative specifications were compared based on statistical significance, model fit, and economic reasonableness. The preferred models retain variables that are supported by regression results and are consistent with expected business drivers.

Figure 17. Summary Statistics

Variable	N	Mean	Std. dev.	Min	Max
OM&A cost	880	304165.58	449380.74	20427.69	5546348
Total cost	880	683782.72	918501.98	41531.95	9774741
Capital cost	880	379617.11	492804.76	13772.34	4466645
Customers	880	1096604	1100189	70536	5905174
Customers per circ	880	958.4779	440.0996	206.0836	3676.866
Labor price	880	112061.05	17956.59	74050	169624.06
Capital price index	880	2.3	0.44	1.85	2.95
Distribution busine	880	0.44	0.19	0.13	0.93
Time trend	880	5.5	2.87	1	10

Sample period	**2015-2024**
Number of utilities	**88**
Number of observations	**880**

Figure 18. Total Cost econometric model

Explanatory variable	Parameter estimate (coefficient)	Multiplier for impact on expected cost (exponentiated coefficient)	T-statistic	P-value
Customers	-0.18	0.83	-0.80	0.42
Customers squared	0.04	1.04	4.88	0.00
Customers per circuit	0.00	1.00	-0.57	0.57
Labor price	0.62	1.86	8.42	0.00
Capital price index	0.25	1.28	5.71	0.00
Distribution business share	0.31	1.36	5.93	0.00
Time trend	0.00	1.00	0.30	0.77

R-squared	**0.948**
Number of observations	**880**
Sample period	**2015–2024**

Figure 19. OM&A Cost econometric model

Explanatory variable	Parameter estimate (coefficient)	Multiplier for impact on expected cost (exponentiated coefficient)	T-statistic	P-value
Customers	0.87	2.39	61.82	0.00
Labor price	0.97	2.64	8.89	0.00
Distribution business share	0.52	1.68	7.24	0.00
Time trend	-0.01	0.99	-1.41	0.16
	R-squared	**0.887**		
	Number of observations	**880**		
	Sample period	**2015–2024**		

Figure 20. Capital Cost econometric model

Explanatory variable	Parameter estimate (coefficient)	Multiplier for impact on expected cost (exponentiated coefficient)	T-statistic	P-value
Customers	-0.05	0.95	-0.21	0.84
Customers squared	0.04	1.04	4.31	0.00
Customers per circuit	0.00	1.00	-2.02	0.04
Labor price	0.40	1.49	4.82	0.00
Capital price index	0.43	1.53	8.13	0.00
Distribution business share	0.04	1.05	0.74	0.46
Time trend	0.01	1.01	1.13	0.26
	R-squared	**0.932**		
	Number of observations	**880**		
	Sample period	**2015–2024**		