# Submission regarding Ontario Energy Board's Spending Pattern Analysis and Capitalization Consultation: A Response to Pacific Economics Group Spending Pattern Analysis Report

On behalf of the Electricity Distributors Association

Date: February 13th, 2026

Advised by Nexus Economics

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# Chapter 1: Executive Summary

The Electricity Distributors Association (EDA) represents Ontario's local hydro utilities - the part of the electricity system closest to customers. Publicly and privately owned Local Distribution Companies (LDCs) deliver electricity to every community across the province. Collectively, the sector owns more than $33 billion in distribution infrastructure and invests over $3.1 billion annually to maintain, modernize, and expand the grid while providing safe, reliable, and affordable service. This is the *Power of Local Hydro*.

Ontario's electricity distributors are central to enabling economic growth, electrification, housing development, and system reliability. They are operating in an environment defined by rapid demand growth, accelerating connections, increased integration of distributed energy resources, heightened cybersecurity risks, and more frequent climate-related events. As articulated in the EDA's vision paper, *Solving Grid-Lock: Our Vision for a Customer-Centric Energy Transition*[1], these structural shifts are fundamentally reshaping both the scale and timing of distribution system investments.

This submission responds to the OEB's January 8, 2026, letter inviting comment on the SPA Report, including the analysis, interpretation and conclusions. In this context, variations in capital and operating expenditures within multi-year rate plans should not be interpreted as inefficient or strategic behaviour. Rather, expenditure timing reflects prudent, policy-aligned responses to evolving customer needs, provincial energy objectives, engineering realities, and the coordinated sequencing of complex, multi-year investments required to modernize Ontario's grid.

These issues are being considered as part of Ontario Energy Board's (OEB) broader review of utility remuneration under the Next Generation Rate Framework (NGRF). As part of that work, the OEB retained Pacific Economics Group Research LLC (PEG) in April 2025 to conduct a Spending Pattern Analysis (SPA). The SPA report released January 8, 2026, reviews historical sector-wide spending and capitalization patterns under incentive regulation.

After careful review, under advisement of our chosen consultant, Nexus Economics (Nexus), the EDA concludes that the SPA findings do not support a fundamental shift in Ontario's performance-based regulatory framework. While targeted refinements may be appropriate where supported by robust evidence, the SPA does not establish a record that justifies wholesale or structural reform.

Importantly, the SPA is a retrospective statistical exercise. By design, it evaluates historical spending patterns, many of which occurred during an extraordinary period marked by the COVID-19 pandemic and related economic volatility. Establishing forward-looking regulatory policy requires explicit consideration of present and emerging realities.

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[1] Electricity Distributors Association, *Solving Grid-Lock: Our Vision for a Customer-Centric Energy Transition* (2024), available at: Solving Grid Lock

Ontario is entering a materially different planning environment. The province has articulated clear policy direction through *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*[2], and the Minister's December 18, 2025, Letter of Direction to OEB under section titled "*Utility Remuneration and Improving Customer Service*,"[3] The initiation of this work has likewise been signaled by the Ontario Energy Board through the recently release of CEO Policy 2026-01.[4] These initiatives emphasize reliability, resiliency, affordability, customer service, and economic competitiveness. They recognize that LDCs must undertake significant capital investments in substations, transformers, digital grid management tools, and system resilience to meet growing demand and electrification objectives.

As described in EDA's vision paper *Solving Grid-Lock,* between $106 and $120 billion from 2024-2050 in cumulative capital investment for distribution may be required under moderate-to-high electrification scenarios. **The dominant risk in this transition is under-building, not over-building. Regulatory measures that constrain capital flexibility based on retrospective spending characterizations would materially increase that risk by discouraging timely and prudent investment.** The central regulatory question is therefore not whether expenditures are evenly distributed within a plan term, but whether the framework enables timely, prudent investment at reasonable cost.

**The independent empirical review prepared for the EDA by Nexus Economics (Nexus) finds that PEG's SPA does not provide a sound evidentiary basis for policy change. Nexus identifies several material limitations:**

- The analysis relies on limited and fragmented data drawn from a short time-period heavily affected by COVID-19 disruptions, without adequate controls for that volatility.
- PEG applies ad hoc measures of "skewness" that are not grounded in established statistical theory and are not supported by formal time-series testing.
- The SPA cannot reliably distinguish between strategic cost deferral and normal operational, engineering, accounting, or regulatory realities.
- Even accepting PEG's descriptive findings, plausible and benign explanations exist for observed spending timing, including multi-year capital project cycles, regulatory approval timing, asset condition management, and efforts to mitigate customer bill impacts.
- PEG's own data show only minimal long-run growth in real, per-customer capital spending, inconsistent with claims of unsubstantiated systematic customer harm.
- Reliance on outdated theoretical constructs, such as the Averch–Johnson hypothesis, is inconsistent with modern empirical literature demonstrating complementarities between capital and operating expenditures in network industries.

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[2] Government of Ontario, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 2025.
[3] Ontario Energy Board, *Letter of Direction — 2026-2027* (18 December 2025), online: Ontario Energy Board https://www.oeb.ca/sites/default/files/OEB%20Letter%20of%20Direction%202026-2027.pdf
[4] Ontario Energy Board, *CEO Policy 2026-01*, "What's New," January 30, 2026, available at: https://www.oeb.ca/regulatory-rules-and-documents/whats-new-newsletter/whats-new-2026-01-30

- A descriptive finding regarding expenditure timing, absent evidence of higher total costs, degraded service outcomes, or customer harm, is not a sufficient basis for tightening Ontario's regulatory framework.

Accordingly, the appropriate forum for any consideration of expenditure patterns is within the broader NGRF consultation, where such issues can be assessed transparently and in the proper context. Any discussion of expenditure timing must remain secondary to the more pressing priorities of enabling capital access, supporting electrification, and aligning utility remuneration with Ontario's forward-looking energy policy. Moreover, any analytical work undertaken in that forum should be grounded in larger established statistical methods, ensure full methodological transparency, and explicitly consider reasonable alternative explanations.

Ontario's electricity sector is undergoing rapid transformation. Regulatory frameworks must support timely investment, reliability, resilience, and growth and not focus narrowly on backward-looking statistical distributions. The Board's efforts are best directed toward ensuring that the remuneration framework remains fit for purpose in a period of unprecedented system expansion and economic opportunity.

**Nexus Economics Independent Expert Review**

To support the development of this submission, the EDA retained Nexus Economics, led by Dr. Larry Kaufmann and Mr. Ralph Zarumba. Dr. Kaufmann brings extensive experience with Ontario's regulatory framework, including prior advisory work to Board staff on the development of both third- and fourth-generation incentive ratemaking models, including the Inflation minus Total Factor Productivity (TFP) approach underpinning Ontario's IRM framework. Mr. Zarumba contributes deep expertise in utility cost analysis, regulatory benchmarking, and financial review. Together, Nexus conducted an independent assessment of PEG's analytical approach, findings, and policy implications. Nexus advised that, in the absence of access to the underlying dataset and computational work, the SPA results should be interpreted with extreme caution, particularly where conclusions are framed in a manner that appears more definitive than the supporting analysis would warrant.

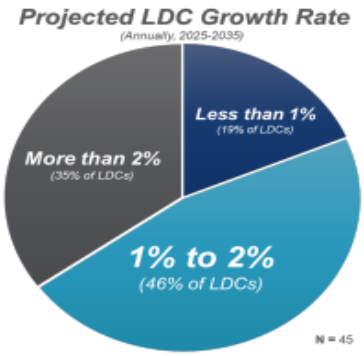
## 1.1 EDA Challenge Statement

Ontario's electricity distribution sector is entering an unprecedented period of expansion and transformation. As documented in the submission, LDCs must respond to accelerating electrification, housing growth, distributed energy resource integration, climate resilience requirements, and cybersecurity obligations, alongside explicit provincial direction under *Energy for Generations* to enable large-scale investment.

As we submitted to the Panel for Utility Leadership and Service Excellence (PULSE) in our December 15, 2025, advice and again on January 20, 2026, supplementary filing[5], Ontario's LDCs

[5] Electricity Distributors Association, Submission to the OEB PULSE Advisory Panel (15 December 2025), and Supplementary Filing (20 January 2026), available at: Review of Ontario's Electricity Distribution Sector

face materially different growth trajectories, balance sheet capacity, ownership structures, and access to financing. Electricity demand is projected to rise significantly, and December 2025 EDA data indicates that nearly half of LDCs expect sustained annual growth of 1 to 2 percent over the next decade. At the same time, approximately half of Ontario customers will be served by utilities facing capital access constraints within ten years, increasing to more than 60 percent within twenty-five years.




**The challenge is structural, not cyclical or patterned. Ontario's regulatory and financing framework was built for an era of incremental, and relatively uniform growth. It was not built for the scale, pace, and uneven capital requirements now emerging**. Without flexible, scalable capital access options, some LDCs will struggle to invest at the levels required to meet provincial policy objectives, economic development goals, and reliability standards.

In this context, it is reasonable to question the immediate regulatory value of the PEG Spending Pattern Analysis. At a time when the sector should be focused on designing a Next Generation Rate Framework that enables timely, efficient, and equitable access to capital, further retrospective examination of expenditure timing risks could divert regulatory attention and introducing uncertainty that undermining investment confidence. The central regulatory question is not whether investment is required, but whether the framework enables all LDCs, regardless of size or financial capacity, to access capital efficiently and equitably to support Ontario's growth and grid transformation.

The EDA welcomes the opportunity to comment on the OEB's ongoing review of NGRF, and we support the development of a modernized regulatory framework that balances affordability, reliability, and long-term system needs. Achieving these objectives requires robust evidence, appropriate analytical tools, and a clear understanding of the operational and regulatory realities faced by Ontario's electricity distributors.

## 1.2 EDA Summary of Evidentiary Observations

The following is EDA's summary of evidentiary observations and were developed in collaboration with our consultants on behalf of our membership and are grounded in the analysis presented throughout this report. For the reasons set out in the Executive Summary and Sections 2–9, and based on Nexus's expert advice, we submit the following:

- **Place no evidentiary weight on the SPA in its current form**, as it is undermined by material deficiencies in data, methodology, statistical testing, interpretation, and policy relevance (Executive Summary; Sections 2–9).
- **If further analysis proceeds, strengthen the evidentiary foundation** by relying on larger, more complete, and more representative datasets (Sections 2 and 4).
- **Incorporate broader North American utility data**, including established U.S. benchmarking and productivity datasets, to enhance empirical robustness and comparability (Section 4).
- **Use established statistical methods**, including formal tests of skewness and kurtosis, rather than ad hoc aggregation measures (Section 3).
- **Control for exogenous disruptions**, including pandemic effects, supply chain volatility, and macroeconomic shocks, before attributing spending patterns to incentive effects (Section 5).
- **Recognize policy-driven timing constraints**, including OEB directives, legislative changes, and provincial energy policy obligations that shape expenditure sequencing (Section 5.1).
- **Evaluate spending patterns in light of operational realities**, such as multi-year project lifecycles, asset management practices, regulatory approval timing, prudence standards, and accounting requirements (Sections 6 and 8.2).
- **Acknowledge the absence of demonstrated customer harm**, as PEG's own results show minimal real capital spending growth per customer over complete cycles (Section 6).
- **Avoid reliance on the Averch–Johnson hypothesis** as a policy basis, given its limited empirical support in capital-intensive network industries (Section 7).
- **Address capitalization issues, if warranted, through structured and transparent processes**, including the Accounting Procedure Handbook and the NGRF review, grounded in demonstrable evidence and materiality (Sections 8.3, 8.4, and 9).
- **Ensure full analytical transparency**, including disclosure of underlying datasets, assumptions, methodologies, and computational steps to enable meaningful stakeholder review and replication (Sections 4 and 9).
- **Conduct any further examination within the broader NGRF consultation**, ensuring alignment with incentive design, benchmarking methodology, and provincial energy policy direction (Executive Summary; Sections 2–7; 9).

The following submissions elaborate on and support the EDA's summary of evidentiary observations regarding PEG's SPA Report within Ontario's rate-setting framework for electricity distributors, with particular focus on the most material methodological, statistical, and policy issues. This analysis is informed by the independent expert advice of Nexus Economics.

# Chapter 2: Findings on Cost Data and Volatility

Before addressing PEG's SPA report, it is instructive to address specific elements of PEG's work measuring total factor productivity ("TFP") growth for energy utility industries. One crucial and important but often unrecognized part of this work is the need to have sufficient data to estimate reliable long-run industry TFP trends. Utility cost data are inherently volatile across years and among utilities, reflecting the impacts of external business conditions, global economic factors, government policy shifts, accounting changes, deferral mechanisms, and ratemaking treatments, which are often outside the control of Ontario Distributors.

This volatility is evident in the empirical research summarized in Section 2, Empirical Research on Ontario Spending Patterns, and illustrated in Figures 1 and 2 below. The figures draw on data from the S&P database and present annual OM&A growth over the past sixteen years for two U.S. distributor samples: first, a subset of relatively small electricity distributors; and second, a larger and nearly complete sample of 82 U.S. electricity distributors over the same period.

Both figures demonstrate that industry-wide OM&A growth fluctuates materially from year to year. However, over a multi-year period, if sufficient cross-sectional and time-series data are available, the ebbs, flows, and idiosyncrasies within utility datasets/expenditures tend to level out, and long-term trends become evident. These dynamics underscore a central methodological point: developing meaningful measures of utility cost growth requires sufficiently large and robust industry datasets. Sufficiently rich data sets are necessary, even to estimate reliable measures of relatively simple average growth rates with reliability.

These data requirements are more demanding when evaluating cost patterns at the individual utility level for two reasons. First, volatility is inherently greater at the company level than at the industry-average level. Second, identifying systematic deviations from the mean, particularly persistent patterns that diverge from industry norms, requires more extensive and higher-quality data sets than simple measuring the mean value of OM&A growth. In the absence of such depth of data, conclusions regarding "skewed" or abnormal cost behaviour lack a statistical foundation.

*Figure 1 - Scatter Plot of Average OM&A Spending Deviations from the Long-run Mean – Small Companies*

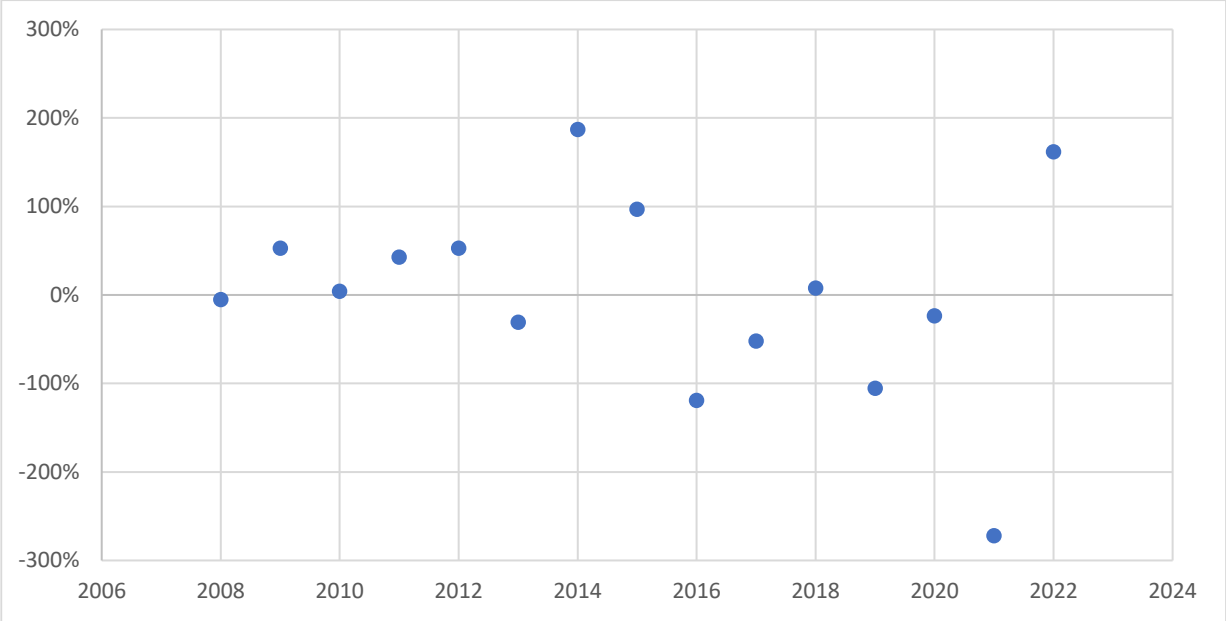
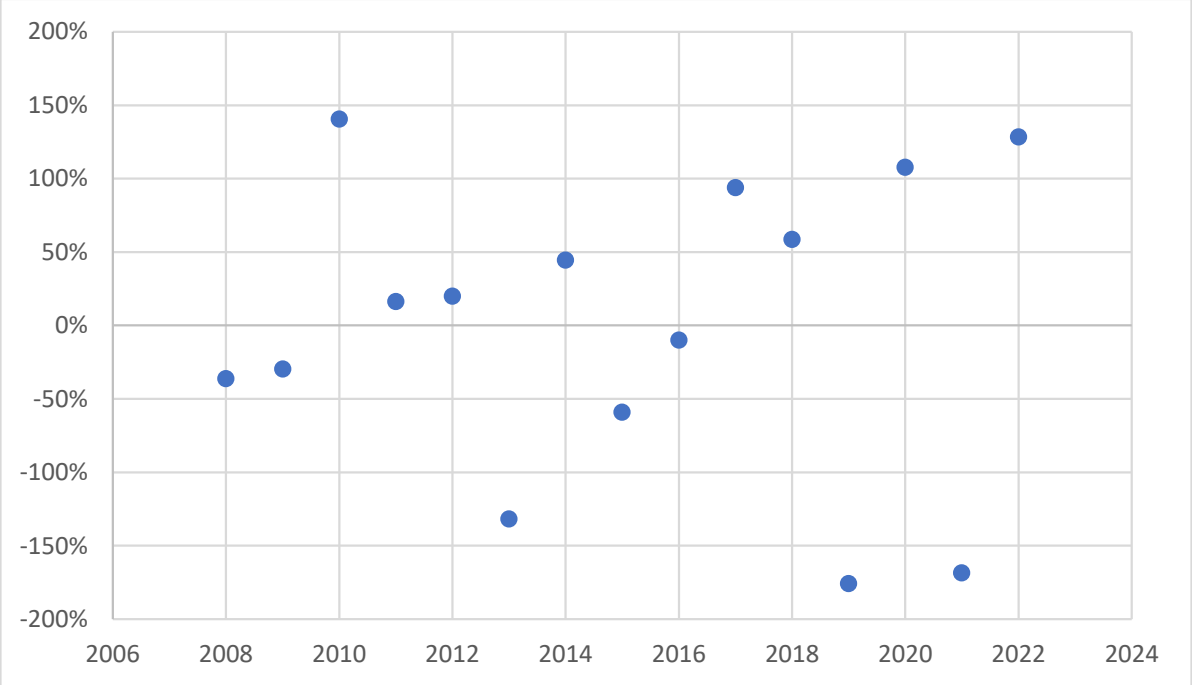



*Figure 2 - Scatter Plot of Average OM&A Spending Deviations from the Long-run Mean – Large Companies*



PEG states in section 2.1 of the PEG report that the SPA analysis relies on Ontario electricity distributor data, which only, covers the 2014–2023 period, and draws on a cross-section of roughly 80 distributors with Reporting and Record Requirement (RRR) data. The empirical results are based on approximately forty-five identifiable rate cycles, supplemented by observations from partial or ongoing cycles, using a standardized five-year rate-cycle framework. **These small numbers of cycles provide a limited amount of time series and cross-sectional information, and they fall short of the data necessary to generate robust statistical results. PEG's data should accordingly be interpreted with caution.** Drawing reliable inferences on complex behaviour, such as distributor-specific spending patterns above and below the long-term spending means – would generally require a larger dataset, and the application of more sophisticated time-series tools/techniques.

PEG's SPA report advances strong conclusions about causal or complex utility behaviour based on a dataset approximately 80% smaller than that generally required for an industry TFP study. While PEG recognizes throughout its report the limitations of its dataset, it should have also been stated that such constraints limit the evidentiary weight that can be attributed to the PEG's SPA report findings, especially when considering structural or industry-wide policy changes.

PEG also appropriately acknowledges in several sections of its SPA report that the empirical results are based on a "fairly small" number of observable rate cycles, Nexus finds that the scope and scale of the available data are inherently insufficient to support strong empirical conclusions regarding systematic, utility-specific spending behaviour. This limitation is particularly evident when the SPA dataset is contrasted with the substantially larger data requirements typically associated with robust long-run industry productivity analysis.

Considering this disparity, based on established standards in empirical productivity analysis, Nexus advises that PEG's available evidence does not provide a sufficient basis for drawing meaningful or rigorous empirical conclusions on the existence, prevalence, or drivers of systematic spending pattern behaviour across time for individual utilities.

# Chapter 3: Measures and Tests of "Skewed" Spending

In Nexus's expert opinion, PEG's SPA report places substantial weight on the concept of identifying and measuring what it characterizes as "skewed" spending patterns over the course of a multi-year rate plan. These alleged skewed spending distortions form the principal empirical basis for PEG's assertion that Ontario's electric utilities are deliberately embracing sub-optimal behaviour and reducing benefits to customers.

PEG's SPA report draws conclusions about distributor behaviour mainly based on broad statistical patterns. But by doing so, PEG overlooks the real-world operational and engineering factors that actually drive investment decisions. As described in EDA's vision paper *Solving Grid-Lock*, Ontario distributors are managing increasingly complex systems, with two-way power flows, growing distributed generation, rising electricity demand from electrification, and greater exposure to extreme weather. These realities directly affect when and how investments must be made.

Distributors make decisions based on detailed, system-specific knowledge that cannot be captured through high-level statistics. As Nexus explains in its expert review, spending decisions depend on asset condition, local system constraints, reliability needs, customer connection timing, workforce availability, and coordination with other system operators. These are practical, on-the-ground considerations that vary by utility and over time to support government policy objectives and reliability standards.

Because of this, spending does not follow a simple or uniform pattern across rate plans. The timing of expenditures reflects informed operational judgment in response to changing system needs not automatic or strategic reactions to incentive regulation. In a period of rapid system change, broad statistical averages cannot fully explain why investments occur when they do.

Nexus finds that because PEG's conclusions are advanced as a potential basis for structural regulatory reform, methodological deficiencies of this magnitude materially undermine the policy relevance and evidentiary weight of the SPA.

Specifically, PEG's analysis:

- Over-interprets aggregate statistical patterns,
- Relies on unsubstantiated assumptions about efficient expenditure timing,
- Fails to adequately account for operational, engineering, and regulatory realities, and
- Underestimates the effectiveness of existing rebasing and prudence safeguards.

Observed variations in spending profiles over a rate term is not, in itself, evidence of a systemic incentive failure. Nor does it justify the imposition of new constraints or corrective mechanisms. On the contrary, the greater risk to Distribution customers and system reliability performance arises from constraining legitimate managerial discretion on the basis of portrayed, aggregate metrics rather than asset-level needs, risk management, and outcomes.

Given the significant role that "skewed" cost data plays in PEG's analysis, Nexus notes that PEG does not employ established statistical tests of skewness or distributional asymmetry drawn from

the econometric or time-series literature. Instead, PEG's approach to identifying skewness appears to be a construct created for this study, not grounded in a recognized or established statistical framework for testing skewness. While the incentive effects of multi-year rate plans are well discussed in the regulatory economics literature, PEG's specific empirical approach to identifying and diagnosing "skewed" expenditures appears to be novel, descriptive in nature, and unsupported by precedent or validated statistical tests of skewed cost behaviour.

## 3.1 Skewness and Kurtosis

"Skewness" is a well-defined statistical concept that is amenable to precise measurement and formal hypothesis statistical testing. Kurtosis is a complementary statistical measure that characterizes the thickness of a distribution's tails and the prevalence of extreme observations. Tests of skewed distributions of variables are sometimes paired with tests of kurtosis, particularly in time-series applications.

In general terms, skewness and kurtosis are statistical metrics that measure the asymmetry of data around the mean of a distribution. Skewness and kurtosis are separate but complementary measures of asymmetry, and both are important for evaluating PEG's work. Skewness measures the direction and relative length of the tail of a distribution, while kurtosis measures the concentration of observations around the mean and the heaviness (or weight) of the tails.

PEG reports that it measures "skew" by aggregating annual cost growth over the early years of an incentive regulation plan and compares that aggregated cost growth to the aggregated cost of growth of the later years of an incentive regulation plan. When total cost growth is higher in the later plan years than in the earlier plan years, PEG characterizes this cost pattern as "skewed."

In essence, PEG defines skew as an asymmetry in cost growth over time: if early- and late-period cost growth are equal, there is no skew; when those growth rates differ, PEG finds that the utility's cost pattern is skewed.

From an econometric perspective, however, identifying asymmetry in a time series requires formal statistical testing to determine whether observed differences are statistically significant or simply the result of random variation. Established skewness and kurtosis tests are specifically designed to assess asymmetry and the overall shape of a distribution. These tests are more rigorous than PEG's ad hoc method and should be applied before any conclusions about "skewed spending patterns" are afforded evidentiary weight.

## 3.2 Testing Skewness and Kurtosis

Testing for skewness and kurtosis are well-established statistical tools that could and should have been applied to PEG's data. Nexus advises that these formal tests should be undertaken and has introduced them for two key reasons:

- First, formal tests would have generated rigorous assessments of, and insights into, how Ontario distributors' cost distributions are spread over time; and

- Second, unlike PEG's ad hoc methodology, established statistical tests of skewness and kurtosis provide a better means of discriminating skewed spending patterns from normal and/or random cost patterns.

To provide an enhanced, more intuitive understanding of testing for skew and kurtosis, Nexus has referenced two relevant pieces from the econometric time series literature. The first of these is replicated below and comes from an advanced time series textbook. This quote indicates that tests of skew are expressly designed to understand the differing distributions of data both above and below the sample mean. The Time Series Textbook states:

> *"A variable with a negative skew is more likely to be far below the mean than it is to be far above the mean"* [6]

This explanation underscores that formal skewness is expressly designed to assess/measure the likelihood that variables are far above or far below the mean of a distribution of data (including utility cost data). Such tests therefore provide a far more rigorous and transparent assessment of "skewed" spending than PEG's bespoke metrics.

We also direct the OEB to a recent peer-reviewed journal article, *"Tests for Skewness, Kurtosis, and Normality for Time Series Data,"* by Jushan Bai (New York University) and Serena Ng (University of Michigan)[7] . The paper presents a clear, systematic framework for testing skewness and kurtosis in time-series applications. Its analytical clarity and methodological rigour make it readily accessible to regulatory experts and provides a practical roadmap for implementing statistically robust tests, which is an approach notably absent from PEG's analysis.

In Nexus's expert opinion, skewness is a well-defined and empirically testable statistical property. PEG's ad hoc assertions regarding "skewed spending patterns" are presented without analytical support and therefore lack methodological foundation. Where a temporal cost series is available, skewness can be directly measured and formally evaluated using established statistical tests. In

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[6] *Time Series Analysis*, 1994, Princeton University Press, pp. 726-49. On p. 746.4

[7] *Tests for Skewness, Kurtosis, and Normality for Time Series Data*. Journal of Business & Economic Statistics, Vol. 23, No. 1 (January 2005), pp. 49–60. Jushan Bai (Department of Economics, New York University) and Serena Ng (Department of Economics, University of Michigan)

such circumstances, it is not reasonable to characterize cost data as "skewed" while declining to apply or disclose the results of those tests. In Nexus's expert opinion, PEG's unsupported characterization is methodologically deficient, cannot support reliable inference, and should therefore be afforded no evidentiary weight by the OEB.

Nexus further recommends that any future analysis in the OEB's Next Rate Generation Framework apply appropriate established statistical approaches to ensure methodological rigour and evidentiary reliability. In addition, analysts should provide all, datasets and computations used to prepare calculated metrics or the results of statistical tests.

If PEG were to argue that its ad-hoc measures cannot, or should not be subjected to rigorous testing, that position would itself seriously undermine the credibility of PEG's conclusions. PEG alleges that Ontario's electric utilities have deliberately skewed their costs over time. This hypothesis requires rigorous supporting evidence, as well as unbiased consideration of alternative hypotheses that might explain the utilities' observed spending patterns. PEG's evidence lacks both rigorous tests of skewed data and a serious consideration of alternate hypotheses explaining utilities' distribution of costs over time.

Nexus therefore strongly recommends that should the Board determine that expenditure patterns warrant consideration, the appropriate forum for such discussion is within the broader NGRF consultation, where they can be assessed in the proper context and as secondary to the structural issues facing Ontario's distribution system and must include rigorous statistical tests of skew and kurtosis across time. If these tests show that PEG's measures of skew and kurtosis are not statistically significant, it is Nexus's expert opinion that the OEB should place no evidentiary weight on PEG's ad-hoc "skewed cost" findings. If the tests for skewness and kurtosis support PEG's claims in the SPA report, other issues regarding data set quality, data transparency, and computations as well as alternate hypotheses still need to be addressed.

# Chapter 4: Data Limitations and Evidentiary Deficiencies in PEG's Analysis

Nexus concludes that, beyond the fundamental deficiencies in PEG's overarching methodological approach, its empirical findings are materially constrained by the limitations of the dataset it selected. PEG relies on a selectively assembled sample of approximately 45 Ontario electricity distributor rate "cycles" drawn from the 2014–2023 period. As PEG itself acknowledges, the dataset underpinning its analysis is incomplete, "fairly small," and sensitive to sorting and classification assumptions, resulting in a limited and fragmented basis for inference. PEG explains that standardized, consistently reported data are not available for all distributors or all years, particularly for capital expenditures before 2014, and that identifying comparable rate cycles is complicated by irregular rebasing schedules, deferrals, plan-length variability, mergers, and differing ratemaking treatments. As a result, the sample cannot be applied consistently across utilities or over time and contains material gaps and inconsistencies in both the periods covered and the data reported, further weakening the reliability of the resulting findings.

These acknowledged constraints have meaningful implications for the evidentiary weight of PEG's conclusions. By PEG's own admission, skewed spending patterns do not arise in a large share of observed rate cycles, and the statistical significance of the results varies materially by cost category, distributor size, and ratemaking treatment. While PEG may be credited for attempting to conduct analysis in a shifting and complex environment, the overall quality and scope of PEG's dataset fall below the standards typically prevailing in Ontario for policy-relevant empirical work. Although PEG appropriately grounded its analysis in Ontario-specific data and the province's regulatory experience, contextual relevance does not inherently require exclusivity of data sources. Additional publicly available North American datasets, including comprehensive time-series and cross-sectional information on utility costs, rate cases, and incentive regulation outcomes, exist and could have provided a broader empirical context. Access to larger and more consistent samples can, in general, support more robust statistical testing of expenditure patterns under performance-based regulation.

In particular, PEG's analysis could have incorporated evidence from utilities emerging from long-term rate freezes and from the many U.S. distributors operating under Performance-Based Regulation (PBR) frameworks comparable to Ontario's MRPs. Given the acknowledged challenges PEG faced in assembling a coherent Ontario dataset, reliance on these broader and well-established U.S. data sources would likely have yielded more reliable and generalizable results. Canadian regulators have routinely relied on U.S. utility datasets in productivity, benchmarking, and incentive-regulation studies, and there is reason to believe that any assessment of alleged "skewed spending patterns" would have been more credible had PEG adopted a similarly rigorous and comprehensive approach.

**Transparency further compounds these concerns**. EDA previously requested, in the Total Cost Benchmarking (TCB) proceeding, that PEG provide access to its underlying datasets, computations, and supporting analysis and respond to inquiries. PEG did not provide that information. The subsequent issuance of the SPA report without disclosure of the underlying data further constrains stakeholders' ability to test, replicate, or independently evaluate the reported findings. In a policy context in which PEG's conclusions are being advanced as a basis for regulatory reform, the absence of complete data transparency materially weakens the evidentiary weight that can reasonably be placed on the SPA report.

Drawing on multi-jurisdictional experience in regulatory benchmarking studies, Nexus advises that reliance on more extensive and mature North American utility datasets would have materially strengthened both the reliability and the evidentiary weight of any findings regarding alleged "skewed spending patterns."

In a policy context where the SPA findings are being considered as a potential basis for reform of Ontario's performance-based regulatory framework, reliance on a limited and fragmented dataset creates a material risk of **regulatory over-correction**. Absent a robust and representative evidentiary foundation, adjustments to incentive design or capitalization policy could unintentionally constrain prudent investment and undermine the Government of Ontario's articulated objectives for reliability, electrification, economic growth, and customer affordability.

# Chapter 5: Sample Period: Policy, Pandemic, and Other Exogenous Influences on Distributor Spending Patterns

It is Nexus's expert evaluation that a material portion of the dataset relied upon by PEG falls within, or immediately adjacent to, the COVID-19 pandemic, an extended period of unprecedented, economy-wide disruption that materially affected operational conditions, cost structures, and capital planning across the sector. During this time, labour markets, global supply chains, construction scheduling, and the procurement of capital and OM&A inputs were materially affected across the electricity sector. These disruptions altered both the level and timing of expenditures, producing abnormal volatility and non-stationary spending patterns that reflect external shocks rather than distributor-specific decision-making under MRPs.

PEG's analysis does not account for pandemic-related effects such as one-time disruptions, system-wide shocks, or deferred expenditures that materialized after the most acute phase of the pandemic. Absent such adjustments, higher spending in later years may reflect postponed work, supply-chain delays, and catch-up activity as constraints eased, not a change in utility incentives or behaviour.

This omission is particularly consequential for the final years of the plan, when deferred projects and purchases would naturally be clustered. As a result, pandemic-related distortions risk being mischaracterized as "skewed" or inefficient spending under PBR, when temporary, exogenous factors beyond utility control are more plausibly to blame. The absence of controls for these effects creates a substantial risk of attribution bias, especially where late-plan expenditures reflect the execution of postponed activities.

More broadly, the analysis also fails to account for global macroeconomic and trade-related shocks that materially influence utility input costs and investment timing. Electric utilities often utilize international supply chains for key materials and equipment and are therefore exposed to geopolitical disruptions, tariffs, and cross-border supply constraints. The recent escalation of trade frictions with the United States underscores that such shocks are not isolated anomalies but recurring features of the operating environment, capable of generating synchronized expenditure patterns unrelated to managerial discretion.

From an econometric standpoint, failing to control for common, externally driven disruptions risks mistaking correlated expenditure timing for incentive-driven behaviour. When similar timing patterns appear across multiple distributors, the more plausible explanation is economy-wide influences rather than firm-specific incentives, operating at the individual company level. In a well-designed PBR framework, such effects are typically addressed through Z-factors or comparable mechanisms that adjust for externally driven cost pressures.

Against this backdrop, the well-documented, economy-wide disruptions that materially affected the timing and delivery of utility work programs provide a compelling explanation for the observed concentration of expenditures in later years. Deferred activity and external constraints offer a more credible account than behavioural responses to incentives. From an econometric perspective,

Nexus advises that failure to control exogenous shocks materially undermines causal inference. Without explicit controls, exclusions, or robust testing to account for pandemic-related and broader macroeconomic effects, PEG's characterization of spending pattern "skewness" lacks analytical support and should therefore be approached with caution and not be relied on for policy-making purposes.

Accordingly, should the OEB elect to pursue further SPA work, any updated analysis should incorporate explicit controls or robustness testing for pandemic-related impacts and broader global economic shocks, to ensure that extraordinary external conditions are not misattributed to incentive-driven behaviour.

## 5.1 Ontario Distributor Policy Environment

Ontario electricity distributors operate within a policy and regulatory environment that materially determines the timing and sequencing of expenditures, independent of PBR incentives. Government and OEB-directed initiatives, legislative and code changes, and system-wide policy objectives are frequently implemented with fixed compliance requirements and defined in-service dates that constrain when work can be executed. In practice, this requires distributors to undertake planning, engineering, and procurement activities over multiple years, followed by concentrated capital and OM&A execution as compliance deadlines approach, resulting in predictable clustering of expenditures within specific years of a plan period. These expenditure patterns are therefore compliance-driven and mechanical, not discretionary. PEG's analysis does not control for these policy-driven timing effects, creating a substantial risk of attribution bias, particularly where late-plan expenditures are observed. To the extent that similar expenditure timing patterns are evident across multiple distributors, this is indicative of synchronized responses to common regulatory and policy obligations rather than incentive-driven behaviour, as PBR incentives operate at the company level. Absent explicit controls, exclusions, or robustness testing for these policy-induced timing constraints, PEG's findings on spending pattern "skewness" cannot reliably distinguish correlation from causation and should therefore be interpreted with caution and not be relied on for policy-making purposes. Interpreting such compliance-driven expenditure timing as inefficient behaviour under PBR would be inconsistent with the Board's longstanding recognition that distributors must respond to externally imposed obligations beyond management control.

## 5.2 Ontario Policy: *Energy for Generations* and Ministerial Direction and Alignment

The Ontario Ministry of Energy's June 2025 integrated energy plan, *Energy for Generations*, confirms that the province is entering a fundamentally different planning environment than the historical period examined in PEG's SPA. The IESO projects electricity demand growth of approximately 65 to 75 percent by 2050, highlighting the magnitude of the investment and system expansion required, as annual consumption increases from roughly 151 terawatt-hours (TWh) in 2026 to approximately

250 TWh by 2050[8]. Meeting this growth will require accelerated, sustained and strategically sequenced investment in the distribution infrastructure. LDCs are being asked to do more than ever before.

The Ontario Minister's June 2025 energy plan, *Energy for Generations*, explicitly affirms that:

"*To meet these growing demands, LDCs will need to strengthen their infrastructure, adopt new technologies, and deliver services more efficiently and affordably. This includes making significant capital investments in substations, transformers, and digital grid management tools.*" [9]

This direction directly contradicts any presumption that future capital clustering or rising distribution investment signals inefficiency. On the contrary, the province has expressly identified substantial distribution capital formation as necessary to support Ontario's economic and electrification objectives.

The Plan is explicit that LDCs must strengthen infrastructure, deploy advanced technologies, and undertake significant capital investment in substations, transformers, digital grid management tools, and resilience measures. It further identifies electrification, housing growth, industrial expansion, severe weather events, and cybersecurity threats as core drivers of sustained capital formation. Under moderate to high electrification scenarios, EDA's vision paper *Solving Grid Lock*[10] cumulative distribution capital requirements are projected to range between $103 and $120 billion. These projections reflect structural system transformation, not cyclical or discretionary timing behaviour.

Whatever direction the SPA review ultimately takes, it must not rely solely on retrospective statistical characterization.

Taken together, these developments materially shift the regulatory context. The drivers of historical spending patterns from 2014 to 2023, including a pandemic-affected sample period, are unlikely to reflect the operational realities distributors will face over the coming decade. Apparent clustering of capital expenditures may increasingly reflect compliance with Ministerial direction, system expansion, resilience mandates, and digital modernization rather than incentive distortion.

Accordingly, regulatory assessment of distributor spending cannot be divorced from Ontario's forward-looking energy policy framework. The central question at this stage of the energy transition is how to enable timely, prudent, and large-scale investment in support of reliability, resiliency, and economic competitiveness. Any consideration of historical spending patterns must remain secondary to, and aligned with, the province's stated objective of powering Ontario's Integrated Energy Plan.

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[8] Independent Electricity System Operator (IESO), *2025 Annual Planning Outlook: Ontario's Electricity System Needs, 2026–2050* (April 2025)
[9] Government of Ontario, *Energy for Generations: Ontario's Integrated Plan to Power the Strongest Economy in the G7*, June 2025.
[10] Electricity Distributors Association, *Solving Grid Lock: Our Vision for a Customer-Centric Energy Transition* (2024)

# Chapter 6: Alternative Hypothesis: Observed Spending Patterns

## 6.1 Alternative Hypothesis of Volatile Cost Data

It should be recognized that reasonable observers may differ in their interpretation of, and conclusions drawn from, PEG's reported cost data. Nexus advises that one reason for this divergence is that the cost information itself is ambiguous, with reported values often fluctuating materially from year to year. In the presence of such variability, differences in interpretation are not only understandable but inevitable.

Further, the evaluation of utility cost data is not value-neutral; it is shaped by the skills, training, and professional experience of those conducting the analysis. Utility professionals bring human capital developed over many years of planning, operating, maintaining, upgrading, and expanding electricity distribution systems. This integrated regulatory, engineering, financial, and operational expertise provides insights that external analysts, by definition, may not possess. Differences in perspective arising from this experience should be given material weight, particularly when grounded in direct, hands-on familiarity with utility assets and system operations.

PEG's analysis gives little meaningful consideration to the possibility that the observed spending patterns reflect factors other than deliberate cost manipulation or attempts to increase customer rates. This omission materially weakens PEG's conclusions. In our view, there are at least three plausible alternative explanations for the observed expenditure patterns, each consistent with prudent utility behaviour and customer benefit. These explanations include: first, the natural lifecycle of multi-year capital projects; second, rational investment deferral to minimize long-run customer costs; and third, accounting and regulatory timing effects that influence when expenditures are recorded rather than when work is performed.

EDA's vision paper *Solving Grid-Lock* explicitly recognizes that contemporary distribution planning increasingly focuses on optimizing costs over time, including the strategic deferral or avoidance of traditional "poles and wires" investments through non-wires alternatives, digital technologies, and improved system visibility. These approaches typically require upfront planning, piloting, and enabling investments, followed by execution once system conditions, customer participation, or policy clarity have sufficiently matured.

Accordingly, the clustering of capital expenditures in later years of a rate term does not indicate inefficiency or opportunistic behaviour. On the contrary, such spending patterns are consistent with disciplined asset management, coordinated system planning, and a deliberate effort to minimize long-run system costs and customer bill impacts. Characterizing these outcomes as "skewed" spending reflects a misinterpretation of prudent investment sequencing and risks attributing improper motives where none are evident. Such an interpretation is inconsistent with, and undermines, the policy objectives articulated by both the Government of Ontario and the OEB.

## 6.2 Multi-Year Capital Project Lifecycle Effects

Utility capital spending projects are almost always implemented over multiple years. These projects typically involve a sequence of discrete phases, each with distinct activities and expenditure profiles. Early stages focus on project planning, engineering, and organizational setup. These initial phases generally involve relatively modest expenditures, although costs may vary depending on regional permitting requirements, contractual arrangements, and associated legal or regulatory processes. PEG itself acknowledges that such external and operational factors can materially influence the timing of recorded expenditures, independent of any strategic intent on the part of utilities.

As the project progresses, utilities begin identifying and procuring the required capital assets and equipment. This procurement phase is typically more capital-intensive than the initial planning stage. The subsequent implementation phase might even result in higher booked costs than earlier phases. Finally, project completion often coincides with a pronounced increase in recorded capital expenditures, as previously incurred costs are formally capitalized and reflected in the utility's financial accounts. PEG recognizes that accounting treatment, capitalization practices, and regulatory mechanisms can affect when costs are recorded, complicating the interpretation of year-to-year expenditure patterns.

Given this well-established project lifecycle, the distribution of utility capital costs over time may naturally appear "skewed," similar to the cost patterns reported by PEG. In both cases, recorded expenditures are relatively low in the early years of a multi-year investment cycle and rise materially in later years. Such a pattern is not irregular; rather, it is a predictable outcome of how capital projects are planned, executed, and accounted for. PEG's own results confirm that such patterns are not universal: a substantial share of complete rate cycles examined do not exhibit late-cycle capital spending surges, and the largest distributors in PEG's sample, which represent a significant portion of customers and assets, do not display the pattern PEG characterizes as "skewed."

## 6.3 Rational Investment Deferral and Cost Minimization

A second possible explanation for PEG's characterization of "skewed" cost data is that utilities may be rationally deferring capital investments to reduce customer costs over time. PEG itself acknowledges that periods of distributor under-earning, external business conditions, and regulatory design can influence the timing of investment decisions. For example, utilities may extend the service life of wood utility poles through enhanced inspection, remediation, and structural restoration programs. While such programs can, in some cases, add up to 20 years to a pole's useful life, the extent of any life extension is inherently uncertain and cannot be determined with exact precision. Consequently, observed time-based variations in capital spending may reflect cautious, cost-minimizing asset-management decisions made in response to evolving operational and financial conditions, and policy drivers, rather than any systematic "skew" in underlying cost drivers. Accordingly, PEG's interpretation of these spending patterns as "skewed" completely overlooks the role of rational investment deferral and might not be supportable over time.

Consider a utility that implements such a program during the early years of a performance-based regulation plan, resulting in little or no capital spending on pole replacements during that period. Near the end of the plan term, however, safety considerations may require the utility to replace those poles. Under PEG's analytical framework, this utility would appear to have generated capital cost "savings" in the early years of the plan, followed by a substantial surge in capital expenditures in later years.

In these circumstances, PEG would characterize the outcome as "skewed" spending, when in fact the timing reflects prudent asset management and rational cost management over time, rather than any inefficient or opportunistic behaviour. While PEG applies formal statistical techniques to identify differences in early- and late-cycle cost growth, its methodology does not establish that such differences are inherently inefficient, nor does it demonstrate that they are inconsistent with sound engineering judgment or long-term customer benefit.

Nexus advises that this concern would likely become more pronounced if PEG's SPA recommendations were implemented, as the proposed approach risks amplifying the very distortions identified in the analysis. PEG's own findings show that spending patterns vary materially by distributor size, regulatory framework, and plan design, and that distributors operating under Custom IR arrangements generally do not exhibit late-cycle capital spending surges. These results underscore that simplified pattern-based displays are insufficient to capture the complex and multi-year nature of utilities' long-term investment decisions.

Even if PEG's measures indicate later-year clustering for some utilities, that observation is not inherently adverse. To be policy-relevant, the evidence would need to show that the timing pattern causes material customer harm, such as higher total spending over complete cycles, deterioration in reliability or service quality, systematic inefficiency relative to comparable utilities, or a demonstrable weakening of PBR outcomes. Nexus advises that PEG's work does not establish these links. Instead, its own results show minimal long-run growth in real capital spending per customer over complete cycles, which is inconsistent with a theory of material customer disadvantage.

## 6.4 No Evidence of Customer Harm in PEG's Data

Lastly, PEG's own data does not support the claim that customers are being disadvantaged by so-called "skewed" utility spending patterns over time. PEG's concern relates to the timing of expenditures within rate cycles, not to excessive capital spending over complete cycles. However, its empirical results show no material escalation in overall capital spending levels when assessed on a real, per-customer basis.

In Section 2.2 ("Capex Spending Patterns") of the SPA report, Tables 1a to 1d, *Capex Patterns of Ontario Electricity Distributors by Rate Cycle Year, 2014–2023*, PEG presents data on changes in a real (i.e., inflation-adjusted), per-capita (i.e., customer-adjusted) capital cost index, including the "Other Adjustment," for all companies in its sample.

PEG's own data show that this adjusted capital cost index increased by an average of only 0.15% per year across all distribution customers over the full sample period examined in the SPA report.

This result is based on the real index growth average of complete cycles only in the index over the five most recent periods in PEG's analysis (T-4, T-3, T-2, T-1, and T-0, the rebasing year).

While capital expenditures per customer do vary from year to year, the overall growth rate is exceptionally small. When assessed on a real, per-customer basis over complete rate cycles, capital spending has remained essentially flat. PEG's own results therefore do not demonstrate that customers are being materially disadvantaged by the timing of capital expenditures, particularly in the absence of evidence that such timing results in higher total costs, degraded service quality, or reduced long-term efficiency. Such a slow increase in capital spending per customer is inconsistent with a presumption that "skewed" spending patterns, as identified by PEG, are inherently harmful to distributors and their customers.

*Table 1: Rate of Change in CAPEX per customer*

**CAPEX Patterns of Ontario Electricity Distributors by Rate Cycle Year per Customer (2014-2023)**

| Year | All Distributors (Table 1a) | Large Distributors (Table 1b) | Medium Distributors (Table 1c) | Small Distributors (Table 1d) |
|---|---|---|---|---|
| **T-4** | -6.05% | 11.83% | -5.83% | -9.17% |
| **T-3** | -2.16% | -4.43% | -1.74% | -2.12% |
| **T-2** | 10.42% | 20.96% | 6.66% | 11.17% |
| **T-1** | 5.49% | -29.90% | 0.68% | 11.69% |
| **T-0 Rebase Year** | -6.95% | 11.25% | 4.23% | -14.48% |
| **Average** | 0.15% | 1.94% | 0.83% | -4.16% |

# Chapter 7: Theoretical Issues

Nexus advises that PEG's SPA report does not adequately reflect how distributor spending patterns are shaped by policy-driven often non-discretionary, investment requirements. EDA's vision paper Solving Grid-Lock documents the need for foundational grid modernization to support electrification, DER integration, climate resilience, and housing development. Many of these investments are required regardless of short-term cost-minimization incentives. They are more appropriately assessed on a best-fit and reasonable-cost basis than through narrow benefit-cost or timing-based efficiency tests.

In this policy context, the timing of expenditures is frequently driven by factors such as regulatory approvals, customer readiness, coordination with government programs, and the availability of enabling technologies. These drivers are largely outside distributor control and cannot be meaningfully assessed using aggregate measures of within-term spending distribution alone.

The majority of PEG's 128-page report is not devoted to empirical analysis. Instead, it focuses extensively on a general review of incentive regulation theory, particularly issues related to information asymmetry between regulators and regulated firms. This literature is long-standing and well understood by regulators, consultants, and parties to regulatory proceedings. As a result, much of PEG's discussion adds little new insight or practical value to the issues before the Board in this proceeding.

While information asymmetries between regulators and utilities are well understood, there is comparatively less recognition of those that can arise between external researchers or consultants and the operational realities of utility firms. This latter issue is addressed in a substantial and sophisticated body of literature, with important implications for the design and assessment of incentive-based regulatory mechanisms. Because this literature is more directly relevant to PEG's work on TCB and TFP growth and benchmarking, we will address it in detail in our forthcoming submissions responding to OEB's NGRF and PEG's TFP and TCB benchmarking recommendations.

That said, one element of PEG's theoretical discussion warrants closer examination. PEG repeatedly invokes the Averch–Johnson ("A-J") effect to support the proposition that utilities systematically over-capitalize their operations and substitute capital for operations and maintenance (O&M) expenditures. PEG mentions this several times and uses this theory to support the view that utilities over-capitalize and/or choose not to use O&M inputs rather than capital in utility operations. Based on six decades of empirical literature, Nexus advises that reliance on the A-J hypothesis as a policy justification is not supported in capital-intensive network industries.

The A-J effect is a theoretical proposition that rate of return regulation creates incentives/encourages regulated utility companies to over-invest in capital assets. The hypothesis was first articulated by Harvey Averch and Leland Johnson in a 1962 article published in the

*American Economic Review*[11] and was subsequently developed by S.H. Wellisz in a 1963 *Journal of Political Economy*[12] article. For this reason, the hypothesis is sometimes referred to as the Averch–Johnson–Wellisz ("AJW") effect.

Since its introduction more than sixty years ago, the A-J hypothesis has been subjected to extensive empirical and theoretical scrutiny and remains one of the most frequently tested propositions in regulatory economics. As with any academic theory, this body of work has produced a range of perspectives and degrees of support. However, taken as a whole, the accumulated evidence has tended to weaken—rather than strengthen—confidence in the empirical relevance of the A-J effect, particularly in capital-intensive network industries. In short, six decades of research have reduced, not reinforced, economists' confidence in the veracity of the A-J hypothesis.

One of the most compelling critiques of the A-J effect comes from Professor Paul Joskow. Professor Joskow is one of the most eminent energy economists over the last 50 years and is a long-standing professor at Massachusetts Institute of Technology (MIT) University. In a 2005 article, Professor Joskow asserted that all the research attempting to find evidence of the A-J effect over the last 15 years was a waste of time and effort.[13] Even more importantly, in 2014, Professor Stephen Law published a comprehensive survey and assessment of research on the A-J effect. Professor Law summarized his findings in the following abstract of his paper:

*This paper expands upon the observation of Paul Joskow (2005) that exploration of the Averch-Johnson-Wellisz (AJW) effect over the previous fifteen years had been a waste of time and effort. In a non-random selection of 192 articles published since 1962, 39% fail to specify or provide results of tests for necessary pre-conditions for the effect and in almost all remaining articles a strong conclusion should not be reached due to problems with single-period estimation, capital price calculations, definitions of output, or input complementarities. In general, there is little evidence to suggest that there was ever an AJW effect*.[14]

In addition, in his review of the 192 most relevant previous studies, Dr. Law found that:

In most of the articles claiming to provide evidence of the AJW effect a strong conclusion should not have been reached due to *(i) single- rather than multi-period estimation, (ii) incorrectly specified capital prices, (iii) problematic definitions of output, or (iv) the reason that for the companies in these regulated industries, installed capital assets are complements to other inputs*. Network industries, which typically have very high capital to labour ratios under any regulatory regime, are frequently characterised by complementarity of capital and labour. The kind of industry

[11] Harvey Averch and Leland L. Johnson, "Behavior of the Firm Under Regulatory Constraint," *American Economic Review*, 1962.
[12] S. H. Wellisz, "Regulation of Natural Gas Pipeline Companies: An Economic Analysis," *Journal of Political Economy*, 1963.
[13] Joskow, P. L. (2005). Regulation and Deregulation after 25 Years: Lessons Learned for Research in Industrial Organization. Review of Industrial Organization, 26(2), 169–193.
[14] Law, Stephen M.," Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities," International Journal of Economics and Finance; Vol. 6, No. 8;

which is most often regulated under rate of return may also be the kind of industry in which we are least likely to see the AJW effect (emphasis added).

The emphasized portion of Dr. Law's conclusion is critical for assessing the ability to substitute O&M for capital in electricity distribution. Careful empirical analysis shows that network industries, such as electricity distribution, "*are frequently characterized by complementarity of capital and labor*" and "*may also be the kind of industry in which we are least likely to see*"[15] the AJW effect.

These empirical results therefore show that capital and O&M inputs are often complements, not substitutes, in network industries. Whenever this is true, the A-J effect will be void, since it assumes that utility companies are substituting capital for O&M inputs in an inefficient manner, in order to increase their returns.

The empirical finding that capital and O&M inputs are frequently complements, not substitutes, in network industries does more than undermine the A-J hypothesis; it also shows that capital and O&M inputs are sometimes linked and moving in the same direction. Empirical research therefore shows only that capital and O&M spending is frequently complementary in network industries, not always complementary. There are still instances where capital spending can reduce the need for incremental O&M spending. Relatedly, enhanced maintenance of utility assets can sometimes extend asset life. The relationships between capital and O&M spending are complex, and the naïve A-J hypothesis that utilities always overcapitalize their networks is not supported empirically.

In short, the naïve application of the A-J effect to electricity distribution—particularly as a general justification for assuming inefficient capital bias—is not supported by the empirical literature and should be treated with considerable caution in this proceeding.

[15] Law, Stephen M.," Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities," International Journal of Economics and Finance; Vol. 6, No. 8

# Chapter 8: Capitalization Policies for OM&A

In Nexus's expert opinion, PEG's analysis of OM&A capitalization practices should be afforded no evidentiary weight. The discussion is mainly theoretical and unsupported by evidence of inappropriate behaviour, accounting noncompliance, or customer harm in Ontario. Although PEG characterizes capitalization policy as an area of significant managerial discretion, this framing understates the constraints already in place. If ROE-driven overinvestment were occurring, one would expect to observe sustained real capital growth per customer, declining productivity, or measurable deterioration in cost performance. PEG's own data show none of these outcomes. Capitalization practices are governed by modified International Financial Reporting Standards (M-IFRS), which are more restrictive than U.S. GAAP, as well as with established requirements for consistency, documentation, audit oversight, and regulatory scrutiny through cost-of-service rebasing proceedings. PEG neither identifies deficiencies in M-IFRS nor demonstrates that distributors have exploited accounting discretion in a manner that undermines regulatory objectives.

PEG also raises concerns about potential incentive effects associated with capitalizing certain OM&A activities, such as asset repair and field work. However, it does not identify any distributor that has applied capitalization practices inconsistently with applicable accounting standards, changed policies inappropriately mid-plan, or produced unjust or unreasonable rates as a result. In the absence of demonstrated misuse or over recovery, proposals to prohibit mid plan capitalization changes or require customer compensation are disproportionate and risk constraining legitimate operational and asset management decisions that evolve in response to changes in technology, safety, reliability, and work practices.

It is also important to recognize that OM&A costs are routinely incurred in placing capital assets into service and are appropriately capitalized as part of the asset's cost. Installation labour and related costs, for example, properly form part of a transformer's capitalized value. Variations in the level or composition of capitalized OM&A across distributors reflect legitimate differences in geography, workforce structure, union representation, and organizational design, not inappropriate accounting treatment.

Ultimately, PEG's concerns rest on speculative incentive effects rather than demonstrated outcomes. Existing OEB mechanisms, including policy guidance and utility-specific prudence review, already address the timing and recovery implications of accounting policy changes. PEG identifies no instance in which these mechanisms failed or resulted in material over recovery. Elevating theoretical risk into generalized policy concern, absent empirical evidence, is inconsistent with the Board's evidence-based regulatory framework.

## 8.1 Capitalization and Ratemaking Considerations

Nexus submits that PEG materially overstates both the customer risk associated with capitalization policy and the need for additional regulatory intervention. While specific accounting changes could create timing differences in cost recovery if not adequately addressed, existing regulatory mechanisms already manage those circumstances. PEG has not identified any instance in Ontario where capitalization practices have resulted in duplicate recovery or unjust rates. When properly applied and reviewed through rebasing, capitalization allocates costs over the useful life of assets and supports intergenerational equity. PEG identifies no evidence of over recovery in Ontario.

Existing ratemaking tools, including cost-of-service rebasing, approved depreciation schedules, prudence review, and Board oversight of rate base, provide comprehensive safeguards governing the timing and appropriateness of cost recovery. PEG's proposed prohibitions or customer compensation mechanisms therefore respond to a hypothetical risk rather than a demonstrated regulatory deficiency. In addition, International Financial Reporting Standards (IFRS) requirements, including International Accounting Standard (IAS) eight, mandate disclosure of changes in accounting policy, and audited financial statements are subject to independent external audit opinions confirming the absence of material misstatement. The OEB relies on audited financial reporting as the foundation for ratemaking determinations, and PEG identifies no example in Ontario where audited capitalization practices have caused material customer harm.

PEG also overstates the implications of capitalization differences for benchmarking and productivity analysis. Modern econometric methods are designed to accommodate accounting heterogeneity and differences in operating models. Variation in capitalization practices is not evidence of gaming and does not invalidate benchmarking results.

More fundamentally, PEG conflates accounting judgment with performance-based ratemaking incentives. Treating accounting policy as a ratemaking concern would invite regulatory second-guessing of audited decisions and expose distributors to asymmetric risk, creating downside exposure if capitalization practices are challenged without corresponding recognition of efficiency gains or improved asset management. Such asymmetry would weaken, rather than strengthen, the incentive properties of multi-year rate plans.

Any concerns regarding capitalization should therefore be addressed, if at all, on a case-specific and evidence-based basis rather than through generic or proactive ratemaking constraints, or how alleged over recovery could occur.

## 8.2 Timing of Rate Approvals and Prudence Discipline

The PEG report fails to account for a critical regulatory constraint, rendering its conclusions about "skewed" spending unreliable. Under established OEB accounting policy and prudence review practice, utilities generally do not add costs to rate base until the Board has approved the underlying capital program and its rate treatment. Until that approval is granted, utilities are expected to apply conservative accounting practices and avoid capitalizing costs that could later be disallowed, modified, or reclassified through the Board's prudence assessment. This discipline is fundamental to protecting customers from the risk of recovering investments that have not yet been determined to be prudent or within scope.

In multi-year rate proceedings, Board decisions are often issued after the start of the first test year. During this period, utilities may undertake necessary preliminary and enabling work such as planning, engineering, procurement, and internal labour to maintain reliability and ensure readiness to implement the approved program. However, consistent with prudence requirements, those expenditures are typically expensed rather than capitalized until formal approval is received.

Upon approval, certain previously incurred costs may be reclassified and capitalized where appropriate. Other early-period expenditures, particularly those already expensed in accordance with approved accounting treatment, may not be recoverable as capital even if they supported the ultimately approved investments. Where regulatory decisions are delayed, this dynamic is amplified: the period during which capitalization is constrained is extended, and the window for recording approved capital additions is correspondingly compressed. The observable result is lower recorded capital additions in the early years of the plan and a concentration of capitalization later in the term.

This pattern reflects adherence to OEB prudence standards and conservative accounting practice, not delayed execution or discretionary deferral by the utility. Any conclusion that early-period capital spending is anomalous or strategically "skewed," without recognizing the impact of approval timing and prudence requirements, is inconsistent with the Board's regulatory framework.

## 8.3 Accounting Guidance

Nexus reminds the OEB that IFRS and U.S. Generally Accepted Accounting Principles are designed for general financial reporting, whereas regulatory reporting serves a distinct purpose and audience. Different instructions may therefore apply to the same underlying cost information. Variations in accounting outcomes do not, in themselves, signal a problem; they reflect differing objectives across financial and regulatory frameworks.

Divergence between financial and regulatory accounting frameworks could increase administrative costs, reduce regulatory efficiency, and introduce uncertainty regarding cost recovery treatment. Distributors may be required to maintain parallel financial and regulatory records, increasing compliance complexity and potentially requiring changes to enterprise resource planning systems and internal controls.

Adopting requirements that depart from recognized financial reporting standards would also move the OEB closer to an accounting standard-setting role, with governance and implementation implications beyond traditional ratemaking oversight and the Accounting Procedure Handbook. While departure from established standards may be warranted at times, it should generally occur only where there is clear evidence of adverse or unintended regulatory consequences. In the absence of such evidence, continued alignment with established accounting frameworks best supports consistency, transparency, investor confidence, and regulatory efficiency for distributors in Ontario.

## 8.4 PEG Position

PEG states on page 45 of its SPA report that “This likely reflects the fact that this [capitalization of OM&A] is not a hot issue in most jurisdictions”. This assertion is inconsistent with EDA’s consultants Nexus’s experience, particularly in the United States, where the capitalization of OM&A and other overhead costs is routinely and closely scrutinized by regulators. While it is true that many U.S. jurisdictions adopt Federal Energy Regulatory Commission (FERC) accounting standards and that application is not perfectly uniform across states, the FERC Form 1—which underpins the majority of benchmarking analyses and is widely relied upon in regulatory proceedings—is prepared in accordance with FERC accounting requirements.

PEG further states on page 47 of its SPA report that "The FERC does not provide specific guidance on utility capitalization policies." In Nexus's expert view, PEG's statement is incorrect. The FERC provides explicit guidance on capitalization practices of overhead and related costs in 18 CFR Part 101[16], including:

- General Instruction No. 9, Distribution of Pay and Expenses.
- General Instruction No. 10, Payroll Distribution.
- Electric Instruction No.4, Overhead Construction Costs; and
- Electric Construction No. 3, Component of Construction Cost.

We agree with PEG that Ontario faces unique challenges in addressing accounting issues, given that some distributors have adopted IFRS and others prepare accounting statements under U.S. Generally Accepted Accounting Principles (GAAP).

If the OEB determines that additional accounting consistency measures are warranted, any such changes should be advanced through the established **Accounting Procedure Handbook consultation** and the **NGRF** and be clearly grounded in demonstrable evidence and materiality. The development of these measures should also reflect core regulatory principles, including meaningful stakeholder engagement, transparency of analysis, and clarity in decision-making rationale. Existing IFRS standards, external audit oversight, and OEB prudence review already provide strong safeguards against inappropriate capitalization.

Capitalization policies directly affect rate base and cost recovery and should therefore be addressed through a structured and transparent process informed by accounting and finance expertise, not through ad hoc determinations or retrospective analytical characterizations. Addressing these matters within the established consultation framework will promote consistency while preserving appropriate regulatory oversight and accountability.

[16] Federal Energy Regulatory Commission, *Uniform System of Accounts Prescribed for Public Utilities and Licensees*, 18 CFR Part 101.

# Chapter 9: Conclusion: Insufficient Evidentiary Basis to Support Moving Forward with PEG's Recommendations in Ontario

PEG's SPA report raises important questions regarding the evolution of performance-based regulation. The EDA and its members share the Board's objective of ensuring that regulatory incentives promote long-term efficiency, reliability, and customer value. However, a careful review of the SPA demonstrates that it does not provide a credible evidentiary basis for concluding that Ontario electricity distributors are engaging in inefficient, strategic, or customer-adverse spending behaviour.

PEG's conclusions rely on limited and fragmented datasets, novel and unvalidated measures of skewness, and analytical methods that do not adequately account for pandemic disruption, global supply chain volatility, regulatory approval timing, or policy-driven compliance obligations. These factors materially influenced the timing and execution of distributor work programs and were beyond management control. The SPA attributes observed patterns to incentive effects without demonstrating causation or ruling out these well-established explanations. Even if expenditure timing differences were statistically significant, PEG does not demonstrate that such timing results in higher total costs over complete regulatory cycles, reduced service quality, or weakened performance outcomes.

The Board has long recognized that expenditure timing alone is not evidence of imprudence or inefficiency. Capital and OM&A spending profiles reflect multi-year project execution, prudence standards, accounting requirements, asset management practices, and compliance deadlines. The SPA does not meaningfully test these operational realities. Instead, it advances an abstract statistical characterization that is disconnected from the engineering, financial, and regulatory context in which utilities operate.

This disconnect is particularly pronounced when viewed against Ontario's forward-looking policy framework. Energy for Generations, and the Minister's December 18, 2025, Letter of Direction emphasize reliability, resiliency, affordability, customer service, and large-scale investment to enable electrification and economic growth. The EDA's vision paper, *Solving Grid Lock*, similarly documents the scale and urgency of distribution system modernization required to support housing, distributed energy resources, and climate resilience. In this environment, focusing on statistical patterns within historical rate cycles risks diverting regulatory attention from the central objective of enabling timely and prudent investment.

Critically, PEG's own results do not demonstrate customer harm. While some rate cycles exhibit late-period capital growth, a substantial share does not, and industry participants expressly informed PEG of the numerous external, policy, and operational factors that influence spending patterns. Moreover, PEG's benchmarking update shows sustained sector cost performance below model expectations, not deterioration. If ROE-driven overinvestment were occurring, one would expect to observe persistent real capital intensity growth, declining productivity, or measurable

cost underperformance. PEG's own data show none of these outcomes. On a real, per customer basis over complete rate cycles, capital spending growth is minimal and effectively flat. There is no evidence of higher total costs, degraded service outcomes, or weakened performance-based regulation outcomes. The SPA therefore does not establish that customers have been disadvantaged.

Reliance on the Averch–Johnson hypothesis further weakens the policy relevance of the SPA. Decades of empirical research show that this theory has limited applicability in capital-intensive network industries such as electricity distribution, where capital and operating expenditures are frequently complementary. The SPA does not demonstrate that Ontario capitalization practices deviate from accepted accounting standards or result in unjust or unreasonable rates.

Taken together, the SPA reflects a backward-looking and overly theoretical approach that is out of step with Ontario's current and emerging energy realities. It does not provide a reliable basis for regulatory reform.

Accordingly, the EDA submits that the Board should place no evidentiary weight on the SPA in its current form. Any further examination of spending patterns should occur within the broader NGRF consultation, be grounded in representative datasets and established statistical methods, explicitly control for extraordinary events, align with provincial energy policy, and be fully transparent.

In the absence of demonstrable inefficiency, customer harm, or deviation from established prudence and accounting standards, regulatory policy should continue to be guided by proven outcomes and rigorous, transparent analysis rather than abstract characterizations of expenditure timing.