Measured Productivity and Energy Accounting: Distributed Generation in Brazilian Electricity Distribution, 2015–2024

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Abstract

Distributed generation separates electricity billing, injection and credit use, making the output quantity in network cost benchmarking consequential. We link Brazilian market and accounting records for 52 distributors over 2015–2024 and reconcile energy fields within the compensation scheme. In 2024, billed plus compensated energy is closer to reported consumption than billed plus injected energy in 50 firms; median absolute relative discrepancies are 0.22% and 12.22%, respectively. Replacing the scheme's billed energy with its recorded consumption produces a 2.84-log-point within-year cost-index adjustment, compared with 2.85 using compensation and 3.46 using injection. These are internal administrative comparisons, not validation against independent meters. Over 2015–2024, the injection-based index difference increases by 3.46 log points, with a conditional distributor-bootstrap interval of [1.50, 5.43]. Holding firms and energy records fixed, changing the cost definition raises this estimate to 5.09 log points under PMSO including central administration. Historical reporting gaps and imprecise short-window elasticities limit extrapolation of the recent reconciliation. The evidence connects a documented measurement discrepancy to benchmark sensitivity without identifying a technological-productivity effect of distributed generation.

Keywords: productivity measurement, electricity distribution, distributed generation, energy accounting, cost functions

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1 Introduction

A distribution network serves consumers whose electricity purchases and use of network capacity need not move together. Under distributed generation, consumers can withdraw electricity, export surplus generation, and use credits against subsequent bills. A quantity recorded for billing can consequently evolve differently from other measures of electricity handled by the network. This raises a measurement question: how much do cost-performance indices change when the energy variable changes, holding the estimation method constant?

We study that question using the expansion of micro and mini distributed generation (MMGD) in Brazil. Aggregate reported injection increases from 0.001% to 7.605% of billed energy between 2015 and 2024. Beyond comparing billed energy with injection, we reconstruct the scheme's billed, consumed and compensated energy from monthly records, preserving signed rebilling entries. In 2024, all four fields have twelve monthly observations for every baseline firm. Billed plus compensated energy is closer to reported consumption in 50 of 52 firms, with a median discrepancy of 0.22%, versus 12.22% when injection is added. This supplies an observable internal reconciliation criterion for comparing the output definitions.

We then recover costs from ANEEL's accounting trial balances and estimate a two-output cost equation. Applying common fitted parameters maps each energy definition into a cost-performance index. In 2024, the adjustment relative to billed energy is 2.84 log points when the scheme's billed energy is replaced by its recorded consumption, close to the 2.85 compensation-based adjustment and below the 3.46 injection-based adjustment. Throughout, a log point means 100 times a change in natural logarithms. The decade-long injection comparison is 3.46 log points, but incomplete early reporting prevents treating the recent reconciliation as validation of a uniform historical correction.

Measurement is central to the interpretation of productivity. Foster et al. (2008) distinguish physical productivity from revenue-based measures and show that their economic interpretations differ. Collard-Wexler and De Loecker (2016) address measurement error in capital alongside simultaneity in production-function estimation. The proxy-variable tradition of Olley and Pakes (1996) addresses unobserved productivity, but does not by itself validate the administrative energy quantity used here. Our application concerns a change in the meaning of a sector-specific quantity, rather than a new estimator for the general measurement-error problem.

Two sectoral literatures provide the context. Work on net metering and revenue adequacy studies cost allocation and cost recovery when self-generation changes electricity billing (Clastres et al., 2019; Felder and Athawale, 2014; Athawale and Felder, 2022; de Castro et al., 2021). Research on network benchmarking studies the choice of inputs and outputs and their implications for measured performance (Jamasb and Pollitt, 2000; Shuttleworth, 2005). Brazilian applications include Pereira de Souza et al. (2010); Cardoso de Mendonça et al. (2021); Costa et al. (2025).

There is also a closely related regulatory antecedent. ANEEL's Technical Note 68/2024 defines market output using conventional billed energy plus energy compensated under the compensation scheme, with voltage-level weights for its DEA benchmarking framework (Agência Nacional de Energia Elétrica, 2024c, p. 13). Incorporating distributed generation into benchmarking output is therefore not a new proposal of this paper. Our contribution has three parts: a firm-level reconciliation against reported consumption, a quantification of the resulting index

differences, and comparisons that separate cost definition from sample composition. The recent reconciliation helps explain why injection and compensation yield different benchmarks; the matched comparisons show how much of the sensitivity comes from the fitted cost elasticity. We do not reproduce ANEEL's weighted DEA scores or claim that its framework uses the unadjusted output of our baseline.

The distinction between injection and compensation is consequential. Neither billed energy plus injection nor billed energy plus compensation is automatically a complete measure of network service. Peak loads, distances, losses, reliability and the direction of flows also matter. We use recorded consumption as an internal accounting benchmark, while retaining injection as a long-window sensitivity definition. All these fields come from the same administrative system and may share reporting errors. Section 3.1 documents the reconciliation and its limits.

The exercise is descriptive. Consumer adoption, tariffs and distributor costs can respond to common conditions, and no variation is used to identify a causal effect of MMGD on efficiency. The measured index also contains cost shocks beyond technology. These limitations constrain the interpretation of the levels; the conditional index difference can still be calculated and its sampling uncertainty reported.

2 A conditional measurement comparison

Let B_{it} denote billed energy, I_{it} injection, and $s_{it} = I_{it}/B_{it}$. Define an injection-adjusted quantity $A_{it} = B_{it} + I_{it}$, so that

$$q_{it} \equiv \ln A_{it} - \ln B_{it} = \ln(1 + s_{it}). \tag{1}$$

This is an identity for the constructed quantity A, not an assertion that A equals physical throughput. For a cost-performance index constructed with common parameters,

$$m_{it}^{k} = -\left(\ln C_{it} - \widehat{\beta}_E \ln E_{it}^{k} - \widehat{\beta}_N \ln N_{it} - \widehat{\alpha}_i\right), \quad k \in \{B, A\}, \tag{2}$$

the difference satisfies

$$\delta_{it} \equiv m_{it}^{A} - m_{it}^{B} = \widehat{\beta}_E q_{it}. \tag{3}$$

The same distributor effect is used in both indices. Allowing the parameters or effects to vary also changes the fitted benchmark, which is a different comparison reported separately below. The common-parameter exercise is a definition of the estimand; it does not require demonstrating that two separately estimated coefficient vectors are equivalent.

For the balanced panel, the reported change is

$$\Delta\overline{\delta}_t = \widehat{\beta}_E \left(\frac{1}{n} \sum_i \ln(1 + s_{it}) - \frac{1}{n} \sum_i \ln(1 + s_{i0}) \right). \tag{4}$$

We average distributor log ratios, rather than evaluate the logarithm at a mean share: in general, $\overline{\ln(1+s)} \neq \ln(1+\bar{s})$. Aggregate sector injection and the average firm-level ratio are reported separately.

The derivative of the conditional difference with respect to s is $\widehat{\beta}_E/(1+s)$. A regression of

δ on s is therefore a construction diagnostic, not an independent test or an exact estimate of β_E. Similarly, a small difference when injection is small follows from the construction and is not independent placebo evidence.

The identity does not remove parameter uncertainty. Conditional on observed q,

$$\mathrm{Var}(\widehat{\delta}_{it} \mid q_{it}) = q_{it}^2 \,\mathrm{Var}(\widehat{\beta}_E). \tag{5}$$

For inference on (4), we resample distributors jointly across all years, reestimate both energy specifications, and reconstruct the mean differences. The 1,999 bootstrap replications preserve dependence between the fitted elasticity and the observed shares. They condition on the original sample screen, the zero-imputation convention described below and the chosen cost model, and do not quantify measurement error or specification uncertainty.

For a translog $f(e,n) = \beta_E e + \beta_N n + \frac{1}{2}\beta_{EE}e^2 + \frac{1}{2}\beta_{NN}n^2 + \beta_{EN}en$, where $e = \ln E$ and $n = \ln N$, the corresponding comparison is

$$\delta_{it} = \left[\widehat{\beta}_E + \widehat{\beta}_{EE}\ln B_{it} + \widehat{\beta}_{EN}\ln N_{it}\right] q_{it} + \frac{1}{2}\widehat{\beta}_{EE}q_{it}^2. \tag{6}$$

The local energy elasticity is $\beta_E + \beta_{EE}\ln E + \beta_{EN}\ln N$. The uncentered first-order coefficient alone is not that elasticity.

3 Setting, accounting records and sample

Energy quantities and consumer units come from ANEEL's SAMP market records. Flow variables sum monthly entries, retaining signed rebilling adjustments. Consumer units are the mean of monthly totals rather than their sum. All observations in the estimation panel contain twelve monthly consumer totals. The broader SAMP panel covers 116 distinct distributor identifiers over the window; the number reporting in an individual year varies.

All ten archived annual files report a generation date of 28 July 2026. Their historical GD category labels are therefore labels in this retrospective extract, not evidence that the same categories or values appeared in the original filings. Without earlier vintages we cannot separate revisions to historical records from changes in contemporary reporting practice.

Costs are recovered from the Balancete Mensal Padronizado (BMP). December balances for result accounts carry accumulated annual expenses; the replication package documents checks of this convention against the following January. The recovered panel has 977 distributor-years. Our main cost proxy is account 6105 minus energy purchased for resale and transmission/connection charges. In 2024, the three totals are R$ 194.0, R$ 112.5 and R$ 36.4 billion, leaving R$ 45.1 billion in the accounting residual.

This residual includes depreciation, amortisation and central-administration allocations. It is not identical to regulatory allowed Parcela B or a pure variable-input expenditure measure. We call it net accounting cost. Absent transmission-account entries are treated as zero in the construction, affecting 129 baseline observations; this convention is an additional limitation of the accounting data. The alternative direct PMSO measure sums personnel, materials, third-party services and other direct expenses, excluding depreciation and central allocations. A separate

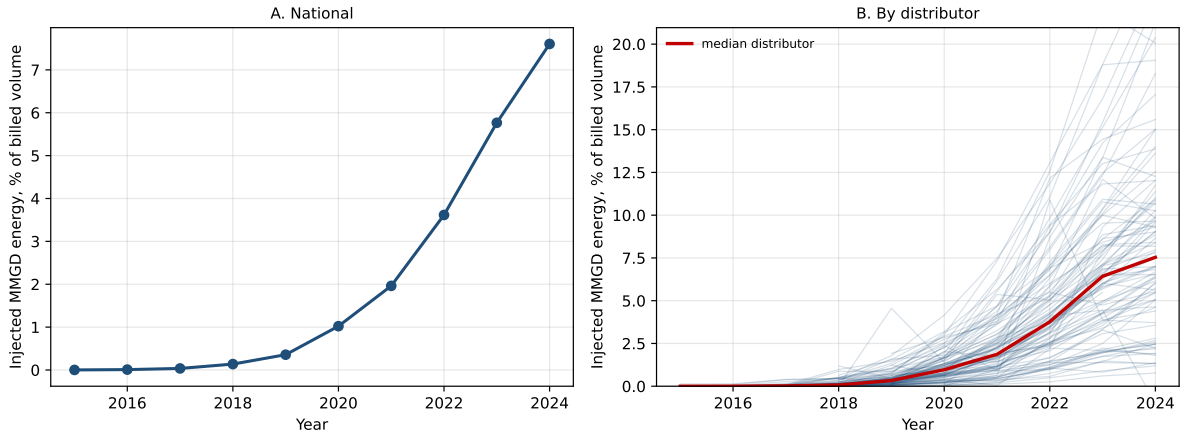


Figure 1: Reported injection relative to billed energy. Panel A uses aggregate sector volumes; panel B shows distributor ratios and the median. Ratios reflect administrative reporting.

Table 1: Brazilian electricity distribution: billed volume, MMGD injection, and consumers, 2015–2024

Year	Distr.	Billed (TWh)	Injected (TWh)	Inj./billed (%)	Consumers (mn)	Median inj. (%)	P90 inj. (%)
2015	102	433.6	0.01	0.001	78.1	0.001	0.01
2016	101	428.1	0.04	0.009	79.8	0.005	0.02
2017	100	432.4	0.16	0.036	81.5	0.019	0.09
2018	108	441.8	0.61	0.137	83.7	0.070	0.45
2019	105	451.4	1.61	0.356	85.3	0.331	1.05
2020	105	438.9	4.49	1.022	86.0	0.963	2.38
2021	105	455.9	8.94	1.962	87.9	1.864	4.65
2022	105	460.4	16.65	3.616	89.6	3.766	9.01
2023	105	473.1	27.28	5.766	91.5	6.427	13.54
2024	103	493.3	37.51	7.605	93.1	7.536	15.48

Source: ANEEL SAMP; distributor-year aggregates. Billed volume is energy billed for distribution-system use (*Energia TUSD*); injected energy is *Energia Injetada* under the compensation scheme. Consumers are means of available monthly totals; the estimation sample has twelve months per year. Median and P90 are across distributors with reported injection within the year; missing injection is excluded from these quantiles. Aggregate injection sums reported entries, with field coverage documented separately in the replication package.

variant adds the four observed central-administration counterparts.

Monthly IPCA inflation rates are compounded to construct a December price index, normalized to December 2024. Annual expenses are deflated by that year's December index. This convention must not be confused with annual-average prices. Common deflator changes are absorbed by the year effects in slope estimation on an unchanged sample, but affect index time trends and can also affect cost-based sample selection.

We retain distributor identifiers with complete coverage and positive core variables, at least one thousand consumers, no consecutive-year absolute log change above 0.25 in consumers or billed energy, and no absolute log change above 0.50 in real net accounting cost. These are log thresholds: 0.50 corresponds to a rise of about 65% or a fall of about 39%. They are diagnostics for large breaks, not documentary proof that concession boundaries were constant. Among matched firms, 25 fail coverage, 17 fail positivity or size, 6 fail the output-break rule and 12 subsequently fail the cost-break rule, leaving 52 firms and 520 observations.

The cost-break rule was added after an initial poor model fit. It is not a pre-analysis restriction independent of outcomes. Coverage of sector billed energy falls from approximately 90% before this rule to 69.4% after it; consumer coverage is 68.5%. The excluded firms are selected on their cost histories. Appendix B isolates this incremental screen, and the sensitivity analysis removes or changes it.

There are 77 missing injection entries and 0 directly recorded numeric zeros in the balanced panel. For the main construction, missing injection is set to zero. We do not classify those entries as verified structural zeros. A sensitivity uses only baseline firms with injection reported in every year; coverage counts by field and year are included in the replication package.

3.1 Injection, compensation and the meaning of output

Injection I records energy exported; compensation K records energy credited against consumption. The two can differ because billing and credit use need not coincide with injection. In the simplified accounting relation $B = D - K$, where D denotes withdrawals from the network, $B + I = D + (I - K)$. Thus $B + I$ recovers D only under additional conditions. Minimum billing, losses, exports and other components require further distinctions before either adjustment can be interpreted as network service.

The reporting history makes a constant field interpretation questionable. Technical Note 235/2022 records guidance issued in June 2021 to include compensation-scheme energy in the captive-supply category of SAMP's energy balance, follow-up guidance in 2022, and uncertainty about compliance (Agência Nacional de Energia Elétrica, 2022). Technical Note 31/2024 addresses further standardization and links the scheme's billed and compensated fields to consumed-energy reporting (Agência Nacional de Energia Elétrica, 2024b). These documents concern the energy-balance mapping; they do not prove that each field in our supply extract changed on those dates. AIR 01/2024 and a regulatory vote also distinguish GD reporting categories and discuss small-distributor market reporting from 2023 (Agência Nacional de Energia Elétrica, 2024a,d). We therefore examine reporting coverage and calendar windows explicitly, without treating a guidance date as an identified intervention.

Within the compensation scheme, let B_G be recorded billed TUSD energy and D_G recorded

consumed energy. We construct

$$W = B - B_G + D_G, \tag{7}$$

replacing this subset's billed energy with its reported consumption while retaining the remaining billed market. The empirical reconciliation compares $B_G + I$ and $B_G + K$ with D_G. For each field, original and signed rebilling entries are summed across regimes and months; "energy debited from SCEE" is retained separately and is not substituted for compensation. The supplement reports the comparisons by month and recorded regime. W is a hybrid administrative proxy, not independently measured network throughput: common reporting errors, minimum billing and other services can still matter.

Table 2 reports the annual comparison. In 2024, the median absolute relative discrepancy is 12.22% for $B_G + I$ and 0.22% for $B_G + K$. Compensation is closer to D_G in 50 firms, although 3 firms still have compensation-based discrepancies above 10%. The result supports compensation as a closer internal match in this extract; it does not establish that every record reconciles. Using the common full-panel elasticity, W implies an adjustment of 2.84 log points, with a bootstrap interval of [1.18, 4.41]. The excess of the injection adjustment over W is 0.62 log points [0.25, 1.06]. These are within-year levels relative to B, not changes since 2015, and do not reproduce voltage-weighted DEA scores.

Table 2: Reconciliation with reported consumption of compensation-scheme customers

Year	Firms	All 12 months	Median abs. error (%) $B_G + I$	Median abs. error (%) $B_G + K$	K closer (firms)	Index adjustment $B + I$	Index adjustment $B + K$	Index adjustment W
2023	52	39	12.86	1.16	45	2.81	2.20	2.26
2024	52	52	12.22	0.22	50	3.46	2.85	2.84

B_G is billed energy in the compensation scheme, D_G its reported consumed energy, and $W = B - B_G + D_G$. Errors are $100|B_G + I - D_G|/D_G$ and $100|B_G + K - D_G|/D_G$; these are internal accounting comparisons, not tests against independent meter readings. All annual fields are observed for the same firms. The third column requires twelve monthly entries for each of B_G, D_G, I, K. Adjustments are $100\widehat{\beta}_E\overline{\ln(E/B)}$ using the same full-panel reference elasticity; they are within-year levels, not decadal changes. The incomplete monthly compensation coverage in 2023 is addressed separately in the text.

Annual availability masks incomplete monthly reporting in 2023. All 52 firms report each field somewhere in that year, but only 39 have twelve monthly entries for all four. In that subset, keeping the full-panel elasticity fixed, the injection, compensation and W adjustments are 3.16, 2.59 and 2.56 log points. In 2024 all 52 firms meet the monthly criterion. Compensation fields are absent before 2023 in this vintage; they remain missing. For a matched 2015–2024 comparison of I and W, only 9 baseline firms report B_G, D_G, I in all 120 months. Their index differences increase by 4.70 and 3.86 log points under the fixed baseline elasticity. Requiring only annual observations retains 22 firms, giving 4.00 and 3.35. These selected reporting cohorts cannot validate the missing early observations or represent the full sector.

4 Cost specification and the interpretation of the index

We estimate the two-way fixed-effects equation

$$\ln C_{it} = \beta_E \ln E_{it} + \beta_N \ln N_{it} + \alpha_i + \gamma_t + u_{it}, \tag{8}$$

with distributor-clustered standard errors. Cobb–Douglas is the baseline; the translog checks sensitivity to its functional form. The cost function is a conditional empirical relation, not a structurally identified production technology. Distributor-level input prices, capital and network length are unobserved. Fixed effects absorb persistent heterogeneity and common annual movements, but do not control firm-specific price changes or expansion within a concession.

Table 3: Cost function estimates: billed versus injection-adjusted energy

	(1) Billed	(2) Adjusted
ln energy	0.3852***	0.4277***
	(0.1266)	(0.1132)
ln consumers	0.2652***	0.2620***
	(0.0994)	(0.0902)
Observations	520	520
Within R^2	0.250	0.260
Residual d.f.	457	457
Distributor FE	Yes	Yes
Year FE	Yes	Yes

Dependent variable is the log of accounting cost net of pass-throughs in December 2024 BRL, from the ANEEL BMP regulatory accounts (account 6105, net of energy purchased for resale and transmission charges). Column (1) measures energy as billed volume; column (2) as billed volume plus MMGD injection. Balanced panel after the disclosed break screens. Standard errors clustered by distributor in parentheses. *, **, *** denote 10%, 5% and 1% significance.

The energy elasticities are 0.3852 (0.1266) for billed energy and 0.4277 (0.1132) for the injection-adjusted quantity. The difference is 0.0425; its paired-bootstrap standard error is 0.0425 and its percentile interval is [-0.0340, 0.1360]. The interval contains zero, which does not demonstrate parameter equivalence. We use the adjusted equation's parameters as a transparent reference for the main comparison. Using the billed equation's energy coefficient instead gives 3.1 log points rather than 3.5 over the decade.

The index in (2) removes a common distributor component but retains common year movements. Those movements can include input-price changes, accounting shocks and technological change; the data do not separate them. It is a relative cost-performance index conditional on the specified outputs, not a direct measure of technical efficiency or total factor productivity. Common components cancel from (3), which makes the conditional measurement comparison tractable without identifying the components of the levels.

The dynamic estimates in Appendix A show substantial lagged-cost persistence but imprecise energy coefficients. They motivate caution about the static cost relation. A difference constructed from a dynamic coefficient would inherit its uncertainty, and a long-run multiplier would require additional assumptions and uncertainty for both the energy and lag coefficients. We keep the estimand in (4) tied explicitly to the static reference model.

5 Results and sensitivity

Table 4 reports a 3.46-log-point increase in the average index difference, with a 95% paired-bootstrap interval of [1.50, 5.43]. The balanced panel's mean injection ratio is 8.59% in 2024, compared with an aggregate ratio of 8.14%. The difference reflects weighting and the distribution of firm-specific ratios, not a monotone relationship between adoption and size. The main index changes are -1.6 log points with billed volume and 1.9 with injection-adjusted volume, but their signs do not survive reasonable alternative specifications.

Table 4: Sensitivity of the cost-performance index to the energy measure

	Injection (% billed)		Missing	Difference		Index change	
Year	Aggregate	Mean	injection	Point	95% CI	Billed	Adjusted
2015	0.00	0.00	29	0.00	[0.00, 0.00]	+0.00	+0.00
2016	0.01	0.01	22	0.00	[0.00, 0.01]	-0.22	-0.22
2017	0.04	0.04	14	0.02	[0.01, 0.03]	-3.58	-3.57
2018	0.15	0.12	7	0.05	[0.02, 0.09]	-2.25	-2.20
2019	0.39	0.48	3	0.20	[0.08, 0.34]	-1.00	-0.80
2020	1.07	1.10	1	0.46	[0.20, 0.75]	+3.17	+3.63
2021	2.03	2.29	1	0.96	[0.41, 1.54]	+6.69	+7.65
2022	3.72	4.47	0	1.85	[0.79, 2.91]	+2.15	+4.00
2023	5.95	6.90	0	2.81	[1.24, 4.41]	-3.53	-0.72
2024	8.14	8.59	0	3.46	[1.50, 5.43]	-1.58	+1.88

Difference and index changes are log points, defined as 100 times the change in logs relative to 2015. Injection is reported in levels; missing entries are set to zero for the main construction. Aggregate shares weight firms by billed energy; mean shares do not. The point difference averages the firm-level identity before subtracting its initial-year mean. Confidence intervals are percentile intervals from 1,999 paired distributor bootstrap replications, conditional on sample selection and the construction of the data. They exclude measurement and model uncertainty. The index levels retain common year movements and are not estimates of technological productivity; their changes are specification-sensitive.

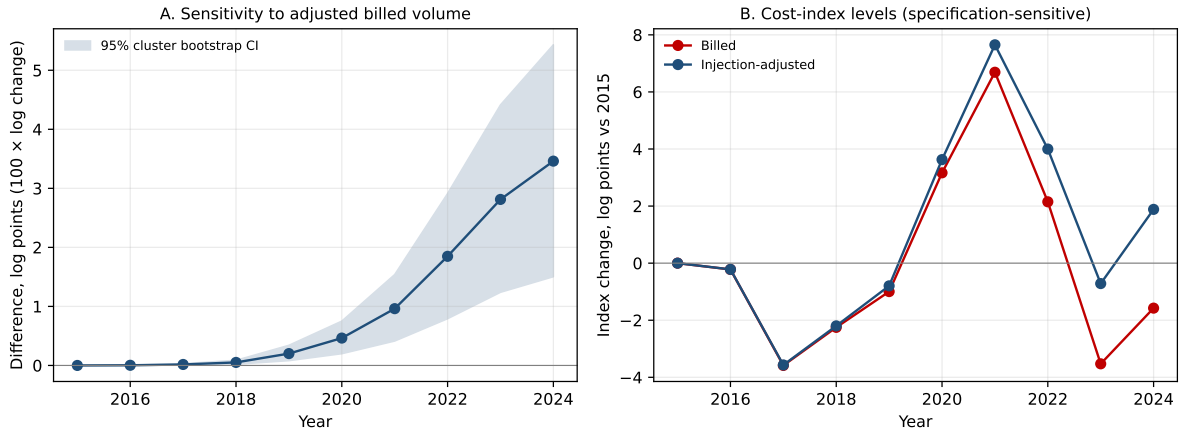


Figure 2: Index sensitivity and its sampling uncertainty. Log points are 100 times changes in logs relative to 2015. Panel A holds the sample-selection and measurement conventions fixed; panel B includes common year movements and is specification-sensitive.

Table 5 holds the firms and their energy records fixed when changing the cost definition. The decadal difference is 3.87 log points for direct PMSO and 5.09 when central-administration PMSO

is added, compared with 3.46 for net accounting cost. This variation is entirely attributable to the fitted elasticity because the observed log ratios are identical. Including purchased energy and transmission expenses raises the difference to 7.63. That dependent variable represents a broader activity than distribution cost alone. The intervals overlap substantially; these comparisons quantify specification sensitivity rather than demonstrate statistically distinct cost elasticities.

Removing R4 retains 64 firms and gives 4.29 log points, but applying the original elasticity to those same firms gives 3.41. A symmetric two-factor decomposition of the change from the baseline attributes +0.89 log points to the elasticity and -0.06 to the distribution of log ratios. Specifically, for alternative (β_1, q_1) and baseline (β_0, q_0), the components are $50(\beta_1 - \beta_0)(q_1 + q_0)$ and $50(q_1 - q_0)(\beta_1 + \beta_0)$, where q is the mean log-ratio change. They sum exactly to the difference in log points. The 33-firm row requires all eleven source accounts underlying the compared costs to be observed in every year; it is stricter than requiring only the three main net-cost accounts.

Table 5: Separating cost definition, sample composition and calendar window

Comparison	Firms	Years	$\widehat{\beta}_E$	SE	Difference	95% CI	Fixed β_E
Net cost, same firms	52	15–24	0.428	0.113	+3.46	[1.50, 5.43]	+3.46
Direct PMSO, same firms	52	15–24	0.479	0.196	+3.87	[0.66, 7.01]	+3.46
PMSO + central, same firms	52	15–24	0.629	0.150	+5.09	[2.46, 7.55]	+3.46
Total opex, same firms	52	15–24	0.943	0.186	+7.63	[4.02, 11.08]	+3.46
No R4 cost screen	64	15–24	0.538	0.213	+4.29	[1.22, 7.79]	+3.41
All cost fields observed	33	15–24	0.544	0.138	+4.90	[1.93, 7.75]	+3.85
Before 2021 guidance	52	15–20	0.203	0.160	+0.22	[-0.14, 0.52]	+0.46
2021–2022	52	21–22	0.191	0.402	+0.40	[-1.04, 1.50]	+0.89
2023–2024	52	23–24	0.456	0.492	+0.69	[-0.29, 2.01]	+0.65

Differences and intervals are log points over each displayed window, with a common parameter vector across energy definitions. The first four rows hold the 52 baseline firms and their energy observations fixed, changing only the dependent cost variable. The next two change the sample under the main net-cost definition. The last three retain baseline firms in different calendar windows; short-window slopes can be imprecise. Each row is reestimated with firm and year effects and distributor-clustered standard errors; percentile intervals use 1,999 distributor bootstrap draws. The last column fixes the full-baseline elasticity and therefore isolates the change in observed log ratios. It does not include a newly fitted slope. These comparisons do not identify the effect of a reporting reform.

The last three rows estimate separate models for 2015–2020, 2021–2022 and 2023–2024 on the same firms, motivated by the documented reporting history. All three index-difference intervals include zero, and the two-year energy slopes are particularly imprecise. Thus the data do not establish stable elasticities across reporting periods or a causal effect of the guidance. These are changes within each displayed window; they omit changes across the boundaries and must not be added to recover the decade-long change. Leaving out each baseline distributor in turn and reestimating the full-window model gives point differences from 3.12 to 3.83 log points. This limits the influence of any single retained firm on the point estimate, conditional on the original screen and reporting conventions.

Appendix C reports the broader sensitivity catalogue, including functional form, alternative screens and continuity controls. Some rows change the sample and cost definition together. Its 12 full-window net-cost variants span 2.9–4.9 log points; this is a range within that catalogue, not a comprehensive robustness bound or a confidence interval. The matched central-PMSO comparison above lies outside it.

The translog's average energy elasticities are 0.3215 and 0.3640. They are evaluated using all the terms of the function, rather than its uncentered first-order coefficient. Local energy monotonicity is violated in 10 billed-output observations and 5 adjusted-output observations, out of 520. These violations limit the model's economic interpretation; they do not show that its average elasticities are negative or that its parameters are unidentified. Applying the full difference in (6) yields 3.01 log points.

Restricting to the 22 baseline firms with injection reported in every year gives a 3.35-log-point difference. This avoids zero imputation but changes the sample and cannot establish the values of missing records. Requiring all three main cost accounts to be reported throughout retains 34 baseline firms and gives 4.87 log points; it avoids filling absent transmission entries with zero but also changes composition. The no-COVID comparison retains baseline firms and omits only the two calendar years; it does not rescreen three-year output changes as annual breaks. In the unbalanced variant, screens use only consecutive calendar-year pairs and changing composition also affects the mean indices.

The two continuity rows use the same 79 firms over 2020–2024. Their differences are 2.96 log points without and 2.97 with the continuity proxies. The proxies sum twelve monthly DEC/FEC observations for each service set and average complete sets equally within a distributor. Without customer weights, these are not official distributor-wide indices. The packaged extract starts in 2020; an official 2010–2019 resource exists (Agência Nacional de Energia Elétrica, 2026), but has not been harmonized for this exercise. This shorter-period comparison is excluded from the decadal headline range.

Sample selection matters particularly for the levels. Without the cost-break screen the billed index changes by 16.1 log points, and changing the cost perimeter also changes its trajectory. There is no basis here for concluding that sector technological productivity rose or fell over the decade.

6 Scope and implications for measurement

The measured sensitivity has become quantitatively material under the specified cost models. Its interpretation is conditional on both the cost elasticity and the meaning of administrative energy fields. Positive differences follow from positive elasticities and nonnegative adjustment ratios; they are not independent evidence that the alternative measure captures true output. The consumption reconciliation provides additional empirical information: compensation tracks that recorded field more closely than injection for most baseline firms in the complete 2024 window. It supports the relevance of the distinction already present in ANEEL benchmarking. Its internal nature and incomplete historical coverage prevent interpreting the result as an independent physical-output validation.

The relationship between firm size and injection is non-monotone in the estimation sample. Table 6 describes that distribution. It does not rule out omitted network characteristics, and it does not demonstrate that the firms with the largest adjustments would otherwise be classified as technologically declining. Claims about absolute efficiency rankings would also require a benchmark that identifies persistent differences between firms.

Table 6: MMGD penetration by distributor size, 2024

Quintile	Distr.	Median consumers	Injection s (% billed)		
		(thousands)	Mean	Median	P90
Q1 smallest	11	6	4.13	3.57	6.96
Q2	10	16	10.06	9.08	13.58
Q3	10	34	9.89	8.08	20.10
Q4	10	1,011	12.32	12.49	22.63
Q5 largest	11	4,079	7.14	6.68	10.28

Quintiles of the balanced panel by consumer units in 2024. Penetration describes the distribution of the injection-to-billed ratio; it is not a test for omitted network characteristics.

Further limits concern selected concession histories, missing accounting entries, the absence of firm-level input prices and network measures, and incomplete historical compensation coverage. The confidence intervals do not cover those sources of uncertainty. Generalizing the estimates to the whole sector or translating them into regulatory efficiency scores would require an explicit account of sample weights, technology and the regulator's output definition.

7 Conclusion

For 52 Brazilian distributors, compensation reconciles more closely than injection with the scheme's recorded consumption in 50 firms in 2024. The resulting 2.85-log-point index adjustment is close to the 2.84 obtained by replacing billed scheme energy with recorded consumption, compared with 3.46 when injection is added. The recent field reconciliation therefore has a measurable consequence for the cost benchmark.

The decade-long injection comparison is 3.46 log points, with a conditional interval of [1.50, 5.43], but the matched cost comparisons and reporting-cohort restrictions show why that number is not a universal correction. Missing historical fields, retrospective data vintages and imprecise short-window slopes constrain extrapolation. The contribution is an auditable reconciliation and a separation of measurement, cost-definition and sample sensitivities. Identifying technical productivity or validating physical network service would require independent information on flows, network characteristics and input prices.

A Dynamic estimates

We estimate a dynamic cost equation with one lag of cost using two-step system GMM (Blundell and Bond, 1998), the finite-sample correction of Windmeijer (2005) and the serial-correlation tests of Arellano and Bond (1991). Instruments are collapsed and restricted to lags two and three. Table 7 reports 18 instruments for 52 groups.

The lag coefficients are 0.6407 and 0.6436. The energy coefficients, 0.2812 (0.5219) and 0.5413 (0.5723), are imprecise. Hansen and AR(2) tests do not reject at conventional levels; this is not proof of instrument validity or sufficient precision. A conditional index difference formed with these coefficients would inherit their uncertainty. The static estimates are not established as

long-run elasticities by this exercise.

Table 7: Dynamic cost function, two-step system GMM

	(1) Billed	(2) Adjusted
$\ln C_{t-1}$	0.6407***	0.6436***
	(0.1260)	(0.1000)
ln energy	0.2812	0.5413
	(0.5219)	(0.5723)
ln consumers	0.0043	−0.2650
	(0.5785)	(0.5851)
Observations	416	416
Groups	52	52
Instruments	18	18
Hansen $\chi^2(6)$	10.55	9.02
p-value	0.103	0.172
AR(1) p-value	0.000	0.000
AR(2) p-value	0.939	0.976
Year effects	Yes	Yes

Two-step system GMM (Blundell–Bond) with the Windmeijer finite-sample correction, estimated with `pydynpd`. Instruments are collapsed and restricted to lags 2–3 to keep the instrument count well below the number of groups. Dependent variable is log net accounting cost in December 2024 BRL. Windmeijer-corrected standard errors in parentheses. *, **, *** denote 10%, 5% and 1% significance.

The lagged dependent variable indicates persistence conditional on the dynamic model. The energy elasticities are imprecise; differences constructed from them would inherit this uncertainty. Non-rejection by Hansen and AR(2) tests does not establish instrument validity. These estimates are reported as a diagnostic of sensitivity to dynamics, not as confirmation of the static index difference.

B The incremental cost-break screen

Table 8 compares the 52 retained firms with the 12 excluded by R4 among firms that already pass coverage, positivity, size and output-break rules. Median consumer counts in 2024 are 34 thousand for retained firms and 1638 thousand for those excluded; mean injection ratios are 8.59% and 7.88% respectively. This comparison does not pool the other exclusion rules or validate the causal source of each cost break. The package includes the full exclusion log and the comparison by rule.

For every R4 exclusion, the supplement reconciles the largest annual net-cost jump with changes in account 6105, purchased energy and transmission, using the original deflation and missing-value convention. Account 6105 has the largest absolute component in 11 cases and purchased energy in 1; 2 bridges include an absent transmission entry. The components sum to the observed net-cost change. This traces the numerical source of the screen but does not identify whether a jump reflects a reclassification, concession change or economic shock.

Table 8: What the cost-break screen removes, 2024

	Distr.	Median consumers (thousands)	Median billed (GWh)	Median cost (R$ mn)	Mean s (% billed)
Included	52	34	198.3	43	8.59
Excluded	12	1,638	6,301.2	860	7.88

Both groups first pass coverage, positivity, size and output-break rules R1–R3. "Excluded" contains only firms subsequently removed by the cost-break rule R4. The full exclusion log and a separate comparison by rule are included in the replication package. Cost is the nominal accounting residual after subtracting the two pass-through categories.

C Additional specification comparisons

Table 9: Sensitivity across cost specifications and samples

				Mean ε_E		Index change (log pts)		
Specification	N	Obs.	Years	Billed	Adjusted	Billed	Adjusted	Diff.
base	52	520	15–24	0.385	0.428	-1.58	+1.88	+3.46
translog	52	520	15–24	0.322	0.364	-0.21	+2.80	+3.01
R4 = 0.35	48	480	15–24	0.305	0.351	-5.52	-2.65	+2.87
R4 = 0.75	57	570	15–24	0.334	0.369	-2.37	+0.62	+2.99
R4 off	64	640	15–24	0.455	0.538	+16.08	+20.37	+4.29
PMSO direct	53	530	15–24	0.417	0.373	+7.20	+10.26	+3.06
PMSO incl. central	59	590	15–24	0.645	0.586	+11.64	+16.48	+4.83
total opex	59	590	15–24	0.799	0.789	+5.11	+11.59	+6.48
trim smallest 25%	39	390	15–24	0.354	0.435	-3.43	+0.62	+4.05
unbalanced	86	715	15–24	0.460	0.432	-0.59	+2.38	+2.96
no COVID (2020-21)	52	416	15–24	0.492	0.515	-1.18	+2.99	+4.17
unrestricted β	52	520	15–24	0.385	0.428	-2.59	+1.88	+4.48
complete injection	22	220	15–24	0.357	0.358	+6.14	+9.49	+3.35
complete cost accounts	34	340	15–24	0.514	0.537	+2.28	+7.14	+4.87
quality sample, baseline	79	395	20–24	0.286	0.431	-5.42	-2.46	+2.96
quality (2020-24)	79	395	20–24	0.293	0.432	-5.45	-2.48	+2.97

Log points are 100 times log changes over each displayed window. Energy elasticities are average derivatives; translog entries include quadratic and interaction terms. A common parameter vector from the adjusted equation is applied to both indices, except in the unrestricted row. R4 thresholds are absolute annual log changes. The no-COVID row retains the baseline firms and removes only 2020–2021. Complete injection retains only baseline firms with reported injection in every year. Direct PMSO excludes central administration transfers; the next row includes them. Complete cost accounts retains baseline firms with all three main cost components reported in every year. The last two rows share the same firms and years, isolating the addition of continuity proxies: annual sums of monthly DEC/FEC, averaged equally across complete service sets. These are not customer-weighted official firm indicators. The packaged extract starts in 2020; an official 2010–2019 resource exists but is not harmonized here. The shorter window is excluded from the headline decadal range. Point-estimate ranges are not confidence intervals.

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