Mismeasuring Productivity in the Energy Transition

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Abstract

Is the energy transition making electricity generation more productive, or only cheaper to build? I identify two biases in measured productivity. First, falling imported wind and solar capital costs should appear as capital deepening, not electricity-sector productivity. Applying the United States new capacity-cost index to historical investment flows, I reconstruct US electric-power TFP and reclassify 2.8 log points of 2011–2024 growth, turning stagnation into decline. Second, renewable generation is self-correlated and increasingly concentrated in low-value hours. Using hourly market data, I show that official accounts miss this value decline, which grows with penetration and eventually overtakes the capital bias.

Keywords: productivity measurement, renewable energy, capital deflators, value factor, electricity.
JEL codes: O47, E01, C82, Q42, Q55.

1 Introduction

Between 2010 and 2024, the installed cost of solar panels fell by 87% and onshore wind by 55% (International Renewable Energy Agency, 2025), declines comparable to transistors and computers (Way et al., 2022; Aizcorbe et al., 2008; Byrne et al., 2018; Nordhaus, 2007). Solow famously observed that computers were everywhere except in the productivity statistics (Solow, 1987; Triplett, 1999); renewables present the same surface paradox. Despite an extraordinary decline in the cost of renewable capacity, measured Total Factor Productivity (TFP) in US electric power roughly stagnated during the past decade. This paper shows that even that flat record was too favourable: once falling capacity costs are recorded as capital deepening rather than electricity-sector productivity, apparent stagnation becomes decline.

In this paper, I show that the productivity-accounting diagnosis differs from Solow's. Falling renewable costs create two measurement problems at different stages of the energy transition. Both overstate measured productivity, and their effects are additive: one understates real capital input, the other overstates real output. Early on in the transition, inadequate capital deflators attribute cheaper equipment to electricity-sector productivity. Later, increasingly simultaneous renewable generation reduces the value of delivered electricity in a way that annual output indexes do not capture. I use a 2023 revision by the US Bureau of Economic Analysis (BEA), which switches to a renewable-specific capital deflator, to measure the first bias: how much published US electricity TFP reflected falling capital prices rather than technical change within electric power. I then use hourly electricity prices and generation to measure the emerging output-value bias. The first bias is front-loaded and fixable by statistical convention; the second is back-loaded and requires more granular output measurement.

A capital deflator determines how much nominal investment is recorded as real capital and therefore how measured growth is divided between capital deepening and productivity. Both TFP growth and capital deepening raise labour productivity and real income in a standard growth-accounting framework, real incomes. However, countries using different capital deflators are not directly comparable in measured productivity, raising the risk that cross-country analyses attribute higher aggregate TFP to greater renewable deployment when part of the difference reflects statistical convention (Rath et al., 2019). For information and communication technologies (ICT), the debate over growth attribution arrived a decade or more into the diffusion, so the productivity record of the 1980s and 1990s had to be corrected ex post. For the renewable transition, if statistical revisions come early, most of the gains will be recorded correctly as they happen.

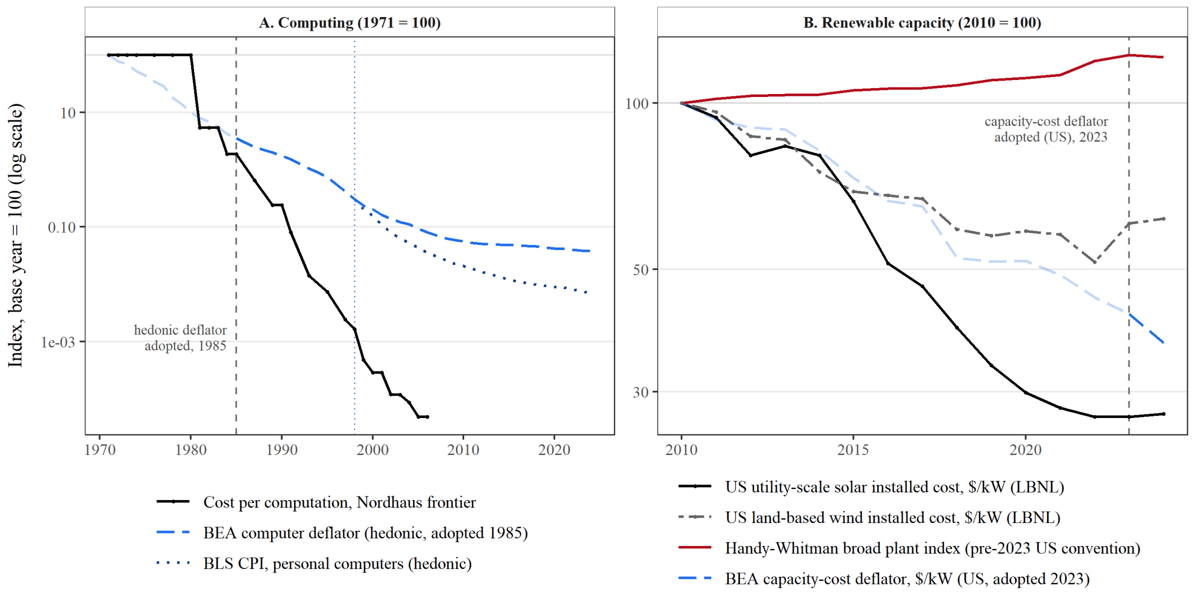

Figure 1: **Two episodes of rapid embodied technological change and statistical adjustment.** All US, real (relative to the GDP price index), indexed to 2010. Panel A compares the cost of computation (Nordhaus, 2007) with official computer price indexes; hedonic adjustment was adopted in 1985, more than a decade into the decline. Panel B compares US utility-scale solar and land-based wind installed costs—capacity-weighted dollars per kilowatt, from the Berkeley Lab utility-scale solar and land-based wind market reports (Seel et al., 2025; Wiser et al., 2025)—with the broad Handy–Whitman electric-plant index (Whitman, Requardt and Associates, LLP, 2026) and the renewable-specific BEA capacity-cost deflator adopted in 2023 and applied back to 2010 (McCulla et al., 2023).

Figure 1 places the renewable transition beside the earlier diffusion of computers, two episodes in which rapid embodied technological change required technology-specific capital-price measurement. The adjustment came much earlier for renewables: in 2023, the BEA replaced the broad construction indexes used for wind and solar structures with renewable-specific dollars-per-kilowatt deflators, applied back to 2010. The broad indexes had changed little over time, thereby understating capital deepening and leaving too much growth in the electricity-sector productivity residual. Since much of this equipment is imported at world prices, the old convention also misattributes upstream and foreign learning to domestic productivity in the sector that happened to install the equipment, similar to the import-price bias of Houseman et al. (2011). A capacity-cost deflator instead records the gain as cheaper capital for the adopter, as a terms-of-trade gain, and, where appropriate, as manufacturing productivity abroad: green innovation does not disappear, but is booked where it occurs. Cheaper capital still raises the amount of productive capital available to the adopter and thereby raises labour productivity.

Renewables also create a second measurement problem with no close ICT precedent. A faster computer does not become less useful because other firms own faster computers, whereas a solar megawatt-hour becomes less valuable when many solar panels produce simultaneously. Annual output measures can therefore overstate the growth of real electricity output, thus, productivity.

Three results follow. The first is an accounting reclassification identified from an official methodological change; the second is a market-data measurement exercise; the third is a calibrated extrapolation.

First, the capital correction shifts the measured productivity record of the deployment decade. Replacing the broad construction deflator with the renewable-specific capacity-cost index reclassifies 2.8 cumulative log points of 2011–2024 gross-output TFP growth, or 4.3 log points on a value-added basis, from the residual into capital deepening. With renewable capital correctly deflated, a near-zero measured productivity record becomes a substantial decline: the rapid deployment of renewable capacity was primarily capital deepening rather than productivity growth in US electric power.

Second, the output-value bias is already visible in market data and it grows with penetration. Across 138 European market-years, wind and solar generation is valued about 2.9% below the average MWh, with the gap reaching 17.5% in West Denmark in 2024. California and Texas, at roughly half that penetration, show gaps of 11.7% and 5.3%. Official output systems distinguish customer classes, tariffs, or destinations, but not the hour and location of delivery, and therefore miss this decline in the value of electricity output.

Third, the relative importance of the two biases changes over the transition. The output-value bias grows with renewable penetration and overtakes the fixable capital-price bias at a wind-and-solar generation share of 40% under the central estimate. The United States remains well below that point, Germany has essentially reached the crossover, and West Denmark has passed it. These crossing points are calibrations rather than forecasts: they hold the historical relationship between renewable penetration and market value fixed, while storage, transmission, demand flexibility, and other forms of adaptation can shift it.

The paper connects three literatures. Relative to the ICT growth-accounting literature, it uses an official change in statistical convention to measure directly the reallocation between capital deepening and sectoral productivity, and shows that renewable electricity adds a second, output-side bias (Jorgenson and Stiroh, 1999; Oliner and Sichel, 2000; Jorgenson et al., 2008; Bils and Klenow, 2001; Syverson, 2017). Relative to the import-price literature, it studies technological progress embodied in a capital good rather than an intermediate input (Feenstra, 1994; Broda and Weinstein, 2006; Houseman et al., 2011). Relative to the electricity-economics literature, it brings the declining market value of intermittent generation into the measurement of sectoral productivity (Joskow, 2011; Borenstein, 2012; Hirth, 2013; Gowrisankaran et al., 2016; Stiewe et al., 2025). The first measurement bias has already prompted a correction to the US statistical system, though not yet to the other systems examined here. The second bias has not: none of the official systems examined in this paper distinguishes electricity output by the hour and location of delivery.

2 Two biases in the electricity residual

Let Y_E denote electricity-sector output, produced from capital K_E, labour L_E, and intermediates M_E under constant returns and competitive factor pricing, with Hicks-neutral level A_E and nominal cost shares s_K, s_L, s_M summing to one. Denoting log changes by hats, measured TFP growth is the Solow residual:

$$\widehat{A}_E = \widehat{Y}_E - s_K \widehat{K}_E - s_L \widehat{L}_E - s_M \widehat{M}_E. \tag{1}$$

The same algebra applies on a value-added basis with intermediate inputs omitted. I report both measures, taking gross-output TFP as the baseline and the value-added result as the corresponding rescaling.

The input wedge. The investment deflator P_K converts nominal investment into real investment, $\widehat{I}_E = \widehat{I}_E^{\text{nom}} - \widehat{P}_K$. Sector capital-input growth $\hat{K}_E$ aggregates the growth of individual assets using each asset capital-services share. Let $\mathcal{R}$ denote the renewable assets, let $\omega_{R,t}$ denote their combined share of sector capital-services, and define

$$\gamma_{K,t} \equiv \widehat{P}_{K,t}^{\text{broad}} - \widehat{P}_{K,t}^{\mathcal{R}}$$

as the growth-rate gap between the broad and renewable-specific deflators.

Proposition 1 (Capital-deflator reallocation)**.** *Holding the asset weights fixed across deflators, switching from the broad to the asset-specific deflator raises measured real capital-input growth by* $\omega_{R,t}\gamma_{K,t}$ *and lowers measured productivity growth by*

$$B_{K,t} = s_{K,t}\, \omega_{R,t}\, \gamma_{K,t}. \tag{2}$$

This amount is reclassified from the measured productivity residual into capital deepening, without changing the nominal accounts.

The allocation result is standard, and nominal cost shares are unchanged because they are recorded from current-price transactions. Equation (2) isolates the direct effect of the deflators at fixed capital-services shares. Section 3 relaxes this restriction by allowing the asset-level rental weights to respond to the deflator convention.

The 2023 revision makes this reallocation B_K directly measurable by applying the two official deflators, old and new, to the same investment flow. I define $B_K > 0$ as the magnitude by which capital-price measurement overstates TFP.

The output bias. Official electricity-output measures do not distinguish delivered MWh by generating technology, hour, or location. Pooling technologies is appropriate, but pooling time and location conditions creates a bias. At a given time and place, a MWh has the same market value whether produced by wind, gas, or nuclear power. Treating generation technologies as separate products would create composition effects and risk recording falling renewable production costs as additional real output.

Across hours and locations, however, MWh are not equivalent: electricity delivered in a scarce hour or a constrained location is worth more than electricity delivered when production is abundant. Variable renewable output is correlated with itself, so as penetration rises a growing share of renewable generation arrives precisely in the hours of abundant renewable supply, when wholesale prices are low. An output index that weights all MWh equally therefore misses the decline in relative value and overstates real output growth. I measure this bias by comparing generation aggregated with equal MWh weights, Q_t^{phys}, with generation aggregated using observed hour-location prices, Q_t^{val}.

Let $h = (m, n)$ index hour-location cells, where $m = 1, \ldots, M_t$ denotes the hours of year t and $n = 1, \ldots, N$ denotes locations. Let $p_{h,t}$ and $q_{h,t}$ denote the corresponding price and quantity. Define $\bar{p}_t$ as the system-wide average hourly price, weighting hours uniformly and locations by load share.[1] It normalizes the technology-specific capture ratios and cancels from their ratio below.

A value-sensitive output measure distinguishes MWh by their hour and location of delivery, valuing each quantity $q_{h,t}$ at its corresponding price $p_{h,t}$. By contrast, the physical-output benchmark simply counts MWh as

$$Q_t^{\text{phys}} = \sum_h q_{h,t}. \tag{3}$$

This benchmark assigns the same weight to every MWh regardless of when or where it is delivered. It is a conceptual approximation to official constructions that omit the hour-location margin (see Supplemental Appendix C.1).

Let $Q_{j,t} = \sum_h q^j_{h,t}$ denote generation by technology j. Its capture ratio is

$$v_{j,t} = \frac{\sum_h p_{h,t}\, q^j_{h,t} / Q_{j,t}}{\bar{p}_t}$$

the generation-weighted price received by technology j relative to the system-wide average hourly price. Summing generation revenue across technologies gives

$$\sum_h p_{h,t} q_{h,t} = \bar{p}_t \sum_j v_{j,t} Q_{j,t}.$$

Let r denote wind and solar generation and d all other generation, which serves as the comparison group. Deflating total revenue by the average price received by other generation, $\bar{p}_t v_{d,t}$, converts revenue into equivalent MWh of other generation, and gives

$$Q_t^{\text{val}} = Q_{d,t} + v_t Q_{r,t} = Q_t^{\text{phys}}\big[1 - \theta_t(1 - v_t)\big], \qquad v_t \equiv \frac{v_{r,t}}{v_{d,t}}, \qquad \theta_t \equiv \frac{Q_{r,t}}{Q_t^{\text{phys}}}. \tag{4}$$

Here, θ_t is the wind-and-solar share of physical generation, while v_t measures the market value of wind and solar relative to other generation. Both are observable in market data. Because the common price benchmark $\bar{p}_t$ cancels from the ratio v_t, it directly compares the average price received by wind and solar with that received by other generation. Thus, $v_t < 1$ means that a MWh of wind or solar has lower market value, on average, than a MWh of other generation.

Proposition 2 (Output-value bias)**.** *If the output account assigns the same value to every MWh within a year, the resulting overstatement of generation TFP growth is*

$$B^{\text{gen}}_{V,t} = \widehat{Q}_t^{\text{phys}} - \widehat{Q}_t^{\text{val}} = -\Delta \log\big[1 - \theta_t(1 - v_t)\big] \approx \frac{\overbrace{(1 - v_t)\,\Delta\theta_t}^{\textit{rising renewable share}} - \overbrace{\theta_t\,\Delta v_t}^{\textit{falling relative value}}}{1 - \theta_t(1 - v_t)}. \tag{5}$$

The bias is positive whenever $\theta_t(1 - v_t)$ increases. This occurs when the wind-and-solar share rises while their relative value is below one, when their value relative to other generation falls, or both. To first order, $(1 - v_t)\Delta\theta_t$ captures the effect of a rising wind-and-solar share, while $-\theta_t \Delta v_t$ captures a further decline in the average price received by wind and solar relative to other generation.

[1] For a single zone, $\bar{p}_t$ reduces to the arithmetic mean of hourly prices.

A natural solution to the output-value bias would be to treat electricity delivered at different hours and locations as separate products. However, it would solve only the composition part: a standard volume index records slower output growth when generation shifts toward lower-value hours or locations, but treats changes in relative prices holding quantities fixed as price changes. Because Q^{val} uses contemporaneous relative prices, it is not a conventional volume index, but captures both effects. I therefore use it as a current-market-value benchmark, asking whether additional generation delivers the same market value as the generation it displaces. For instance, holding quantities fixed a fall in the relative price of midday electricity would leave a volume index unchanged but would lower Q^{val}. Thus, both components of B_V arise on the output side, but only the composition component is unambiguously an output-volume measurement bias; the other captures declining market value.

Proposition 2 applies only to generation, whereas the measured sector also includes transmission and distribution. To express the correction in whole-sector TFP units, I therefore scale the generation bias by w_G, the share of sector output coming from generation rather than from delivery

$$B_{V,t} = w_G B_{V,t}^{\text{gen}}, \qquad w_G \simeq 0.585.$$

I measure w_G as EIA generation revenue divided by BEA gross output for NAICS 2211, matching the output concept used in the sector productivity accounts. The ratio averages 0.585 over 2012–2022. Across years and comparable US and European measures, estimates range from 0.52 to 0.65 (U.S. Energy Information Administration, 2026b; Eurostat, 2026a) (Supplemental Appendix F).

Timing of the two biases. The two biases run on opposite clocks. B_K is front-loaded: it is large while renewable-capital costs are falling rapidly and exposure is rising, and disappears once the capacity-cost deflator is adopted. B_V is back-loaded: it is small at low renewable penetration, then rises as penetration increases and renewable generation becomes increasingly concentrated in low-price hours. Section 5 quantifies the crossover between the two.

3 Capital-price bias and BEA revision reallocation

3.1 Decomposition of the capital-price bias

This subsection quantifies how much measured electricity-sector productivity is reclassified as capital deepening when renewable investment is deflated by capacity cost rather than a broad construction index. I report two accounts. A transparent net-stock benchmark makes the arithmetic directly auditable from published capital stocks, while the preferred Hall–Jorgenson account measures capital input using rental-weighted capital services. The preferred account reclassifies 2.8 gross-output and 4.3 value-added log points over 2011–2024, turning near-zero measured productivity into declines of 3.1 and 5.0 log points. I construct the deflator gap, renewable exposure, and capital share in turn, then show how allowing rental weights to respond produces the preferred estimate.

Price gap γ_K. Before its 2023 comprehensive update, the BEA deflated wind and solar structures using broad Handy–Whitman construction indexes that did not cover alternative-energy structures. The update introduced an "alternative-electric" index based on EIA installed costs per kilowatt and applied it back to 2010. Because installed capacity is the asset being replaced, this technology-specific index better matches the replacement-cost concept used in capital measurement (OECD, 2001).

Between 2010 and 2024, the broad index rose by 52.8 log points while the alternative-electric index fell by 66.5, producing a cumulative gap of $\gamma_K = 119.3$ log points (BEA NIPA Table 5.4.4). The measured decline is not generated by a shift from wind toward cheaper solar. Because the BEA series is a chained price index, a change in the mix of renewable investment does not by itself count as a price decline. The index also does not treat improvements in the services delivered by a kilowatt as additional real investment. To the extent that better turbines or solar installations cost more, it therefore records some quality improvement as a higher price, making the measured price decline smaller rather than larger. Supplemental Appendix A.6 detail both points.

Renewable-capital exposure, ω_R. The relevant exposure is the renewable assets' share of sector capital input. Because s_K covers the whole sector, its denominator must likewise include all NAICS 2211 capital, including equipment, transmission, and distribution. Official capital-services weights are not published at the required asset split. Table 1 therefore reports two alternatives: a transparent net-stock benchmark that fixes the observable current-cost stock share, $\widetilde{\omega}_{R,t}$, at its 2011–2024 mean, and the preferred Hall–Jorgenson account, which uses annual two-period rental exposure, $\bar{\omega}^{\text{cap}}_{R,t}$. Applied to the observed deflator gaps, the two measures imply cumulative capital-input wedges of 8.64 and 6.81 log points, respectively.

The renewable category is BEA asset SU60, alternative-electric structures, whose current-cost share of total NAICS 2211 capital rose from 3.6 percent in 2011 to 11.2 percent in 2024. This input exposure is distinct from wind-and-solar generation penetration, an output share of 17.2 percent in 2024. Section 5 uses the observable stock share for the forward exercise; because it produces the larger capital wedge, it yields a later crossover and is conservative for when the output-value wedge overtakes the capital-price wedge.

Capital share, s_K. The deflator choice changes measured real capital but not the nominal current-price factor payments from which $s_{K,t}$ is calculated. In the net-stock benchmark, I fix the capital share under both deflators at its 2011–2024 arithmetic mean,

$$s_K^* = \frac{1}{T}\sum_t \bar{s}_{K,t}.$$

The preferred account instead retains annual variation, applying the standard two-period share $\bar{s}_{K,t} = (s_{K,t-1} + s_{K,t})/2$ under both deflator conventions.

From the direct effect to the preferred capital-services account. Equation (2) holds fixed the asset weights used to construct capital input. The preferred Hall–Jorgenson account instead recomputes them under each deflator convention (Hall and Jorgenson, 1967). Intuitively, these weights are rental weights measure each asset's contribution to the cost of using capital, rather than its share of the capital stock. Because measured asset-price changes affect both real capital growth and the cost of using the asset, the deflator enters twice: it changes the growth assigned to renewable capital and the weight that renewable capital receives in aggregate capital services.

Let $j \in \{\text{capacity}, \text{broad}\}$ denote the convention and $\bar{v}^j_{a,t}$ the corresponding two-period average rental weight. The same weights define renewable exposure when summed over the repriced assets and aggregate capital-input growth when applied to all assets:

$$\bar{\omega}^j_{R,t} = \sum_{a\in\mathcal{R}} \bar{v}^j_{a,t}, \qquad \widehat{K}^j_{E,t} = \sum_{a\in\mathcal{A}} \bar{v}^j_{a,t}\widehat{K}^j_{a,t}.$$

The resulting TFP reclassification is the capital term of the Solow equation (1)

$$B_{K,t}^{\text{services}} = \bar{s}_{K,t}\left(\widehat{K}_{E,t}^{\text{capacity}} - \widehat{K}_{E,t}^{\text{broad}}\right). \tag{6}$$

Using the capacity-cost weights as the reference gives

$$B_{K,t}^{\text{services}} = \bar{s}_{K,t}\left[\bar{\omega}_{R,t}^{\text{capacity}}\gamma_{K,t} + \sum_{a\in\mathcal{A}}\left(\bar{v}_{a,t}^{\text{capacity}} - \bar{v}_{a,t}^{\text{broad}}\right)\widehat{K}_{a,t}^{\text{broad}}\right]. \tag{7}$$

The first term is the direct fixed-weight effect; the second is the response of the rental weights to the deflator convention. If those weights are invariant, the second term is zero and Equation (7) reduces to Equation (2).

Capital-deflator correction. The transparent net-stock benchmark produces a larger correction than the preferred capital-services account, but the qualitative conclusion is the same: capacity-cost gross-output productivity is negative under both constructions. In the preferred account, the direct effect of 3.52 log points is partly offset by a -0.72 rental-weight response, yielding the headline reclassification of 2.81. Falling costs embodied in renewable capital therefore belong in capital deepening rather than in the electricity-sector productivity residual.

3.2 Why we cannot directly compare official TFP vintages

A simple comparison of the published TFP of utilities before and after the 2023 comprehensive update cannot identify this effect directly. Indeed, over 2011–2021, the update raised measured capital input by 1.9 log points, as the new deflator would imply, but raised Utilities TFP by 5.9 log points because intermediate-input revisions dominated (Supplemental Appendix A.1). Treating the comprehensive update as a single-change experiment would therefore give the wrong sign.

Table 1 instead isolates the effect of the deflator convention directly. It applies the old and new deflators to the same nominal investment flow and holds output and all other inputs fixed. The magnitude of B_K is not driven by changes in nominal investment or by how assets are classified: the nominal investment series is essentially unchanged across vintages, and even reallocating 10% between renewable and conventional structures changes the preferred estimate by only 0.3 log points (Supplemental Appendix A.5).

3.3 Who gets the learning curve?

In the framework of Section 2, sourcing creates no third measurement bias; it determines the price path entering γ_K in Proposition 1. Imported equipment follows the global learning curve, whereas production for a smaller domestic market may follow a shallower local curve. With the broad construction deflator, this difference passes into $B_K = s_K\omega_R\gamma_K$ and changes how much upstream learning is recorded as domestic electricity TFP. With the capacity-cost deflator, it changes measured capital deepening rather than electricity-sector TFP. Proposition 2 is unaffected because the output-value bias depends on when and where electricity is delivered, not where its equipment was produced.

I develop an illustrative model to trace how sourcing reallocates learning gains between electricity and manufacturing. To a first approximation, installed renewable-capital prices follow an experience curve, falling by $b\,\Delta\ln Q_{\text{cum}}$ as cumulative deployment rises, where b is the learning elasticity. For example, a 20% cost decline with each doubling of cumulative deployment implies $b = 0.322$. The calibration below allows this elasticity to differ between solar and wind.

Table 1: **Capital-deflator revision and U.S. electric-power productivity.** Direct deflator effet (Panel A) + rental-weight response (Panel B) = total B_K = broad-deflator productivity − capacity-cost productivity.

Panel A. Common deflator gap and alternative measures of renewable-capital exposure, 2011–2024

	Component	Net stock (constant means)	Capital services (annual, preferred)
	Broad electric-infrastructure deflator growth, $\Delta \ln P_K^{\text{broad}}$	+52.8	
−	Capacity-cost deflator growth, $\Delta \ln P_K^{\mathcal{R}}$	−66.5	
=	Deflator gap, $\gamma_K = \sum_t \gamma_{K,t} \equiv \Delta \ln P_K^{\text{broad}} - \Delta \ln P_K^{\mathcal{R}}$	**+119.3**	
×	Renewable-capital exposure (2011 → 2024)	mean $\widetilde{\omega}_R^* = 0.0724$	0.013 → 0.114
	exposure concept	current-cost stock, $\widetilde{\omega}_{R,t}$	rental, $\bar{\omega}_{R,t}$
=	Cumulative capital-input bias (log points)	$\widetilde{\omega}_R^* \gamma_K$ 8.64	$\sum_t \bar{\omega}_{R,t}\, \gamma_{K,t}$ 6.81
×	Sector capital share, gross output	mean $s_K^* = 0.498$	0.442 → 0.578
=	Direct productivity effect, gross output (log points)	$s_K^* \, \widetilde{\omega}_R^* \gamma_K$ **4.30**	$\sum_t \bar{s}_{K,t}\, \bar{\omega}_{R,t}\, \gamma_{K,t}$ **3.52**

Panel B. Capital-deflator reclassification of measured TFP, 2011–2024

Capital-input account	Sector capital share	Broad-deflator TFP	Deflator reclassification, B_K: Direct effect	+ Rental-weight response	= Total B_K	Capacity-cost TFP
Gross-output basis						
Net stock, constant mean shares	0.498	+3.6	**4.30**	—	4.30	−0.7
Capital services, Hall–Jorgenson (preferred)	0.442 → 0.578	−0.3	**3.52**	−0.72	**2.81**	**−3.1**
Value-added basis						
Net stock, constant mean shares	0.779	+4.7	6.73	—	6.73	−2.1
Capital services, Hall–Jorgenson (preferred)	0.772 → 0.797	−0.7	5.37	−1.03	**4.33**	**−5.0**

Notes: Deflator changes and productivity effects are in log points; exposures and factor shares are fractions. Cumulative values sum the changes 2011-2024. Calculations use unrounded values, so displayed components may differ slightly because of rounding. Arrows report 2011 and 2024 values; parentheses report the sample range. Panel A reports gross-output effects. The *net-stock account* fixes renewable exposure and factor shares at their 2011–2024 arithmetic means. Both broad- and capacity-deflator productivity are recomputed using these constant mean shares. Its direct capital correction is $B_K^{\text{stock}} = s_K^* \widetilde{\omega}_R^* \gamma_K$. The *preferred capital-services account* instead applies the annual two-period factor shares, $\bar{s}_{i,t}$, and Hall–Jorgenson rental exposures, $\bar{\omega}_{R,t}^{\text{cap}}$, year by year. The two accounts therefore differ in both their capital-input measure and their factor-share treatment. Both broad- and capacity-deflator productivity are computed using these Törnqvist capital shares.
In Panel B, capacity-cost productivity equals broad-deflator productivity minus B_K, so positive B_K denotes a downward productivity revision. For the preferred account, total B_K equals the direct effect plus the response of the rental weights to the deflator convention. This response is not applicable to the net-stock account.
The series are constructed for NAICS 2211 and are not published BLS productivity measures. The exercise changes only the renewable-structure deflator, holding nominal investment, output, and non-capital inputs fixed. Sources are BEA NIPA Table 5.4.4, BEA Detailed Fixed Assets and industry accounts, BLS, and EU KLEMS. Supplemental Appendices A.1, A.3, and A.4 provide construction details.

For technology $j \in \{s, w\}$, let m_j denote the growth of global cumulative capacity, $s_{d,j}$ country d's share of global additions, b_j the elasticity of installed cost with respect to cumulative experience, and w_j its weight on technology j in the BEA wind-and-solar capacity-cost deflator. Starting both sourcing regimes from the same inherited experience stock, the reduction in the broad-deflator residual under full reshoring is

$$B_K^{\text{off}} - B_{K,d}^{\text{re}} = s_K \omega_R \sum_j w_j b_j \ln\left(\frac{m_j}{1 + (m_j - 1)s_{d,j}}\right). \tag{8}$$

Equation (8) is a no-spillover counterfactual: with complete international knowledge spillovers, domestic producers continue to track the global frontier and the difference vanishes.

The technology-specific curves reproduce the measured 66.5-log-point decline in the renewable capacity-cost index under global experience. Restricting subsequent learning to domestic experience reproduces only 27.9 log points in the United States and 34.6 in the EU. Full reshoring therefore reduces the broad-deflator electricity residual by 1.4–2.3 value-added log points in the United States and 1.2–1.9 in the EU. Reshoring also creates additional domestic manufacturing learning. Even under an upper-bound calculation that attributes the entire resulting cost improvement to manufacturing TFP, however, the gain is only 0.36 and 0.44 electricity-sector-equivalent log points, respectively. Supplemental Appendix B provides the experience-stock, domestic-content, and manufacturing calculations.

The broad-deflator residual is therefore largest under global sourcing: electricity appears most productive when its capital embodies the deepest learning curve, even when that learning occurs upstream or abroad. This is the capital-input analogue of the offshoring bias in Houseman et al. (2011): unmeasured declines in imported intermediate-input prices appear there as domestic manufacturing productivity, while unmeasured declines in renewable-capital prices appear here as electricity TFP. Reshoring relocates some learning to domestic manufacturing, but the estimated manufacturing gain is substantially smaller than the resulting reduction in the electricity-sector residual.

4 The output-value bias

The previous section showed how the 2023 BEA deflator revision resolves the input-side measurement problem for renewable investment, but it does not resolve the second bias defined in Section 2. I first establish that official output indexes omit the relevant hour-location margin, then measure it from European and US market data and state the benchmark under which it is additive to B_K.

4.1 Why official output does not resolve the value bias

Official systems construct real electricity output in three main ways: direct quantity indexes, deflation of current values, or quantity extrapolation. The methods differ, but the documented US and European implementations share one feature: they aggregate electricity by customer class, tariff, product, or destination, not by the hour and location of delivery. This is explicit in direct-quantity systems such as Norway's, where physical electricity volumes enter the output measure without differentiation by delivery time. As a result, they cannot distinguish a MWh delivered when electricity is scarce from one delivered when renewable supply is abundant.

The implication depends on how real output is constructed. Direct-quantity and extrapolation methods assign equal weight to each MWh and therefore miss shifts toward lower-value hours. In deflated-value systems, part of the decline may already enter measured real output if lower capture prices reduce recorded revenues more than the output deflator. In US electric power, regulated tariffs, long-term contracts, and internal transfers limit the direct link between wholesale capture prices and recorded revenues, making full absorption of the bias unlikely. I do not estimate this pass-through directly. Supplemental Appendix D.7 derives the incidence condition and discusses the remaining uncertainty.

This missing distinction is not foreign to national-accounting principles. ESA 2010 explicitly recognizes time of delivery as a potential quality characteristic of electricity. The problem is therefore not the underlying concept but the level of detail at which it is implemented. By contrast, the accounts are right not to distinguish electricity by generation technology: conditional on its time and place of delivery, a MWh is the same product whether generated by wind, solar, nuclear, or gas. Using source-specific production costs as output deflators would instead create artificial real-output growth.

The US aggregates illustrate why the omitted margin cannot be reconstructed after the fact: Between 2017 and 2024, nominal NAICS 2211 output and its deflator rose by 25.3 and 25.5%, leaving official real output essentially flat, while the Federal Reserve's physical-output index for the same NAICS cut rose by 6.3% (Board of Governors of the Federal Reserve System, 2026). The official measure thus failed to register the increase in physical electricity supplied, and neither series resolves the time-of-delivery margin (Supplemental Appendix D.6). This creates the same identification problem encountered on the capital side, with a different solution. B_K cannot be inferred from changes across official TFP vintages because other inputs were revised at the same time. Similarly, B_V cannot be recovered by manipulating annual output aggregates because the relevant hourly and locational information has already been averaged out within the published strata. It must instead be constructed directly from hourly market prices and generation. Section 4.2 provides the relevant test: holding the underlying data fixed, the bias appears when output is stratified by delivery time or system state.

4.2 Measuring the output-value bias

I implement the value-weighted output index in Equation (4) by pricing each MWh at the day-ahead price for its bidding zone and hour. This price measures the marginal market value of electricity at the time and location of delivery. It therefore differs from the revenue received by the generator, which may also include support payments or contract terms such as feed-in tariffs, contracts for difference, and power purchase agreements.

I estimate the output-value bias using hourly market data from a European panel (ENTSO-E) containing 138 bidding-zone-years from 15 zones over 2015–2024. I apply the same construction to CAISO over 2020–2025 and ERCOT over 2018–2025. For each technology $j \in s, w$, penetration θ_j is generation divided by load and the value factor v_j is its generation-weighted capture price relative to the time-weighted baseload price (Hirth, 2013). A value factor above one means that the technology tends to generate in relatively high-price hours. Supplemental Appendix E provides the full construction. The output-value gap is

$$D = \theta_s(1 - v_s) + \theta_w(1 - v_w). \tag{9}$$

Holding penetration fixed, a lower value factor increases D; more generally, the gap is largest when a technology both supplies a large share of load and earns a low price relative to baseload. Equivalently, $D = 1 - Q^{\text{val}}/Q^{\text{phys}}$. Thus D is the proportional shortfall of value-weighted output relative to physical output: it measures how much lower output is when each MWh is valued at its market price rather than counted equally.

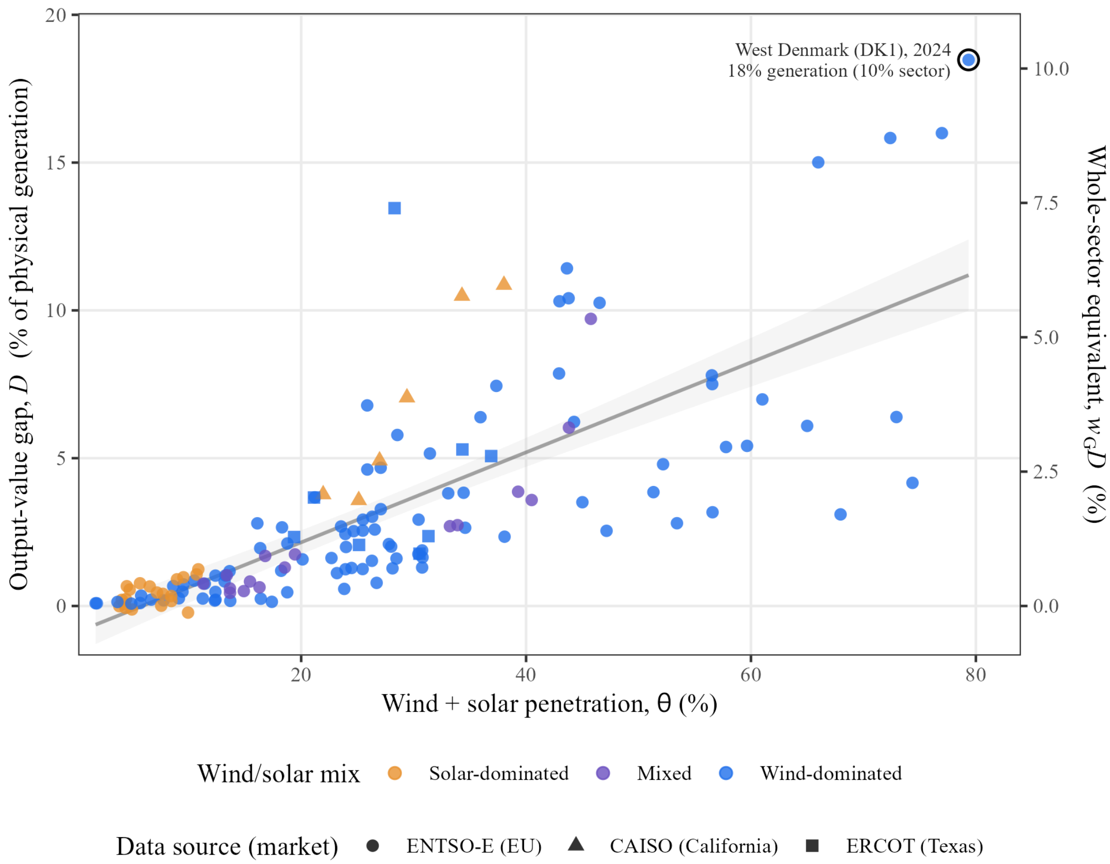

Figure 2: **The output-value gap rises with wind and solar penetration.** Each point represents one market-year. The horizontal axis reports total wind and solar penetration, $\theta_s + \theta_w$. The left vertical axis reports the combined output-value gap, $D = \theta_s(1 - v_s) + \theta_w(1 - v_w)$: the proportional shortfall of market-value-weighted generation relative to physical generation. The right axis expresses the same gap in whole-sector units, $w_G D$, using $w_G = 0.585$. Colour denotes whether renewable generation is solar-dominated, mixed, or wind-dominated, and marker shape identifies the market. The solid line is an OLS fit through all observations, with a pointwise 95% confidence band. The sample contains 152 market-years: 138 from 15 European bidding zones over 2015–2024 (ENTSO-E, 2026), six from CAISO (2020–2025), and eight from ERCOT (2018–2025). The data are constructed from hourly day-ahead prices, generation, and load, with negative prices retained. West Denmark in 2024 has an output-value gap of 17.5%, equivalent to 9.6% in whole-sector units. The elevated ERCOT observation in 2021 reflects Winter Storm Uri.

Figure 2 shows the level of the output-value gap. It averages 2.9% across European market-years, rising from 0.6% among low-penetration, solar-dominated observations to 3.4% among high-penetration, wind-dominated observations, and reaches 17.5% in West Denmark in 2024. Multiplying by $w_G = 0.585$, the sample mean corresponds to 1.6% of whole-sector output and the West Denmark observation to 9.6%. CAISO and ERCOT lie on the same penetration–gap relationship: at 38 and 35% wind-and-solar penetration in 2024, their gaps were 11.7 and 5.3%. Alternative treatments of negative prices and curtailment leave the European results essentially unchanged (Supplemental Appendix E.5). These are differences in output levels, not annual TFP biases.

A chained Törnqvist index applied to the same hourly data isolates the quantity-composition channel. The result depends on how delivery products are defined: month-by-hour cells produce a 6.2-log-point bias in solar-dominated CAISO but little in wind-dominated ERCOT, whereas residual-load strata produce 6.9 and 7.2 log points, respectively. Across Europe, the residual-load estimate is positive in 13 of 15 zones, with a median of 0.76 log points. The exact decomposition of (5) attributes 34% of the cumulative European bias and 41% of the US bias to quantity composition, with relative-value decline accounting for the remainder. Supplemental Appendix E.6 reports the full results and price-shock sensitivities.

This contrast matches the mechanism: solar output is closely tied to clock time, whereas wind varies substantially across days within the same clock-time cell. The bias is therefore not weaker in wind systems; it requires strata that capture the relevant system state (Supplemental Appendix D).

The Figure 2 is descriptive rather than causal. Because penetration enters D directly, its upward slope combines the greater weight placed on renewable generation with any accompanying decline in its value factor. It therefore cannot identify the forward value-factor schedule used in Section 5.

The level gap D maps into annual generation-TFP overstatement through (5), $B^{\text{gen}}_{V,t} = -\Delta \log(1-D_t)$, and into sector units as $B_{V,t} = w_G B^{\text{gen}}_{V,t}$. Thus, when the output-value gap D widens over time, value-weighted generation grows more slowly than physical generation, raising measured generation-output growth. Holding measured inputs fixed, it therefore overstates generation TFP growth by $B^{\text{gen}}_{V,t}$. In whole-sector units $B_{V,t}$ averages 0.29 percentage points per year across the European panel—-0.03 before 2020 against $+0.53$ after—and removing common annual price movements lowers it to 0.06, erasing part of the cannibalisation and making that a lower bound. In the two US markets where the construction is possible it averages 0.90 percentage points per year in CAISO and 0.23 in ERCOT (Supplemental Appendix E.4). Section 5 compares these magnitudes with the capital bias at matched penetration.

4.3 Additivity and non-overlap of the biases

The additivity of the effects of the two biases on TFP,

$$\text{TFP bias}_t = B_{K,t} + B_{V,t}, \tag{10}$$

holds under a specific benchmark: the input deflator prices what a kilowatt costs to build, while the output measure values what the delivered electricity is worth. The BEA capacity-cost index satisfies the first half of this benchmark. It is a replacement-cost measure per installed kilowatt, not an asset-price index capitalizing the expected capture prices of future output. Lower expected capture prices may affect how much capacity is built and the rents that it earns, but they do not constitute a decline in construction costs. A dollars-per-expected-lifetime-MWh deflator would import the value factor into capital services and mechanically offset the output correction. Such an index could be used under a different accounting benchmark, but it could not then be added to B_V.

The output-side restriction is parallel: electricity is differentiated by its hour and location of delivery, not by its generating technology. Supplemental Appendix C.3 shows that assigning source-specific cost deflators to clean and conventional generation creates two artificial output terms even when the output-value bias is set to zero: a composition effect when the generation mix shifts across technologies with different imputed costs, and a learning effect when clean output is deflated by its falling production cost. At the current US clean share, the latter would add roughly 2 percentage points per year to measured real output growth. Neither term represents additional electricity delivered or a change in its market value.

These restrictions keep the two biases separate. B_K measures how the capital quantity associated with a given nominal investment flow changes when renewable capacity is deflated by its replacement cost. B_V measures how the value of delivered generation changes with its timing and location. The first corrects the measurement of inputs; the second corrects the valuation of output. Neither correction contains the other.

5 The crossover between the two biases

5.1 Current systems' biases

The two biases evolve differently over the transition, so Figure 3 compares them over a common path of wind-and-solar penetration on a common whole-sector TFP basis.

To extend the two biases beyond the observed data, I express both as functions of wind-and-solar penetration, θ. For the capital bias, I set current-cost renewable-capital exposure equal to penetration, $\omega_R(\theta) = \theta$, beyond the range observed in the United States. For the output-value bias, I let technology-specific value factors decline linearly with penetration, $v_j = v_{0,j} - a_j\theta_j$, and use Hirth (2013) as the central calibration, (Stiewe et al., 2025) for robustness, and alternative wind–solar schedules to form the band. On this common whole-sector basis, the two biases cross at $\theta^\star \simeq 0.40$.

The biases have different bases and trajectories. B_K scales with renewable capital exposure, which is bounded because sector capital also includes transmission, distribution, and other unaffected assets, and with the price gap γ_K, which narrows as technologies mature. B_V instead scales with renewable generation, which can keep rising toward most of output, and with the value discount $1 - v$, which deepens with penetration. The capital bias is therefore front-loaded, while the output-value bias grows in importance later in the transition.

The 2024 positions (black diamonds) on Figure 3 illustrate the change in the dominant bias. The United States ($\theta = 0.17$) and EU average (0.29) remain in the region where the capital bias dominates and correcting the capital deflator removes most of the measured bias. Germany (0.44) is near the central crossover; and West Denmark (about 0.75) is well beyond it, in the region where the larger measurement is the valuation of output. CAISO at 0.38 and ERCOT at 0.35 show that leading regional markets can approach the crossover well before the US national average. Both measured points nonetheless lie below the central schedule. ERCOT is a relatively isolated market, so the neighbouring-penetration component of the cross-border slope does not apply to it. CAISO's shortfall is more plausibly the growth of its battery fleet, which is one of the two margins considered next.

Two assumptions pull the reported crossover in opposite directions. Setting $\widetilde{\omega}_R = \theta$ overstates the forward capital bias relative to the 2024 US data, where the repriced renewable assets account for 11.2% of total sector capital ($\widetilde{\omega}_R = 0.112$), compared with wind-and-solar penetration of 17.2%. The preferred capital-services exposure is lower still — rental weighting averages about $0.79\,\widetilde{\omega}_R$ (Supplemental Appendix A.3) — so the assumption is conservative on the exposure margin under either exposure concept. It therefore moves the crossover to the right, making 0.40 conservative, without affecting the historical US estimates, which are measured on data. Conversely, omitting future adaptation through storage[2] and other flexibility may overstate the decline in value factors and place the reported crossover too far to the left. The two margins are reported separately rather than netted.

The 40% crossover is a calibration rather than a forecast: alternative wind–solar value-factor schedules move the full-bias threshold from roughly 33% to 52%, while the exposure assumption

[2] Note that storage capital is subject to the same capital deflator story as the first capital bias, as the cost of batteries has also been following an exponential learning-curve (Way et al., 2022).

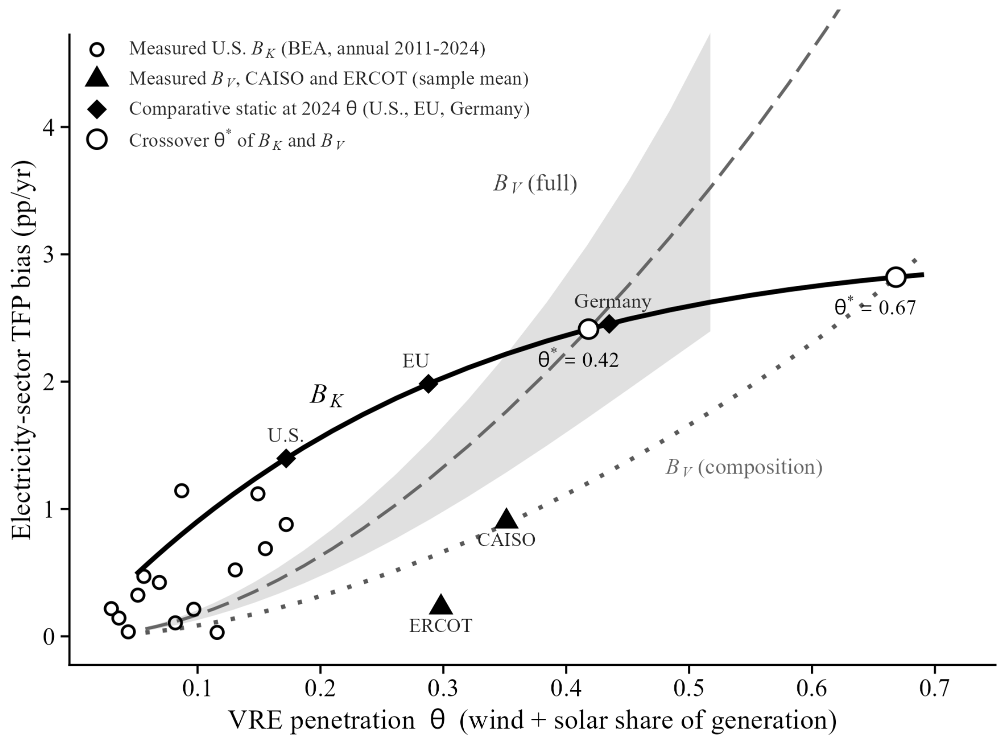

Figure 3: **The dominant measurement bias shifts with renewable penetration.** The solid curve is the capital-price bias $B_K(\theta)$, calibrated to the IRENA installed-cost decline and the measured US deflator gap; open circles use the observed current-cost renewable share of NAICS 2211 capital, $\widetilde{\omega}_R$. The dashed curve is the full output-value bias $B_V^{\text{full}}(\theta) = w_G B_V^{\text{gen}}(\theta)$, with the shaded band spanning alternative wind–solar mixes. The dotted curve retains only the quantity-composition channel of (5); it is a lower-bound specification, not the lower edge of the band. All biases are in whole-sector units, and filled diamonds mark 2024 system positions at the observed wind-and-solar share of generation (Ember, 2025). Filled triangles mark the average measured output-value bias in CAISO and ERCOT, the two US markets (annual values are volatile, ranging from −0.27 to +2.68 in CAISO and −6.99 to +6.83 in ERCOT). The central full bias crosses B_K at $\theta^\star \simeq 0.40$, compared with $\theta^\star \simeq 0.63$ under the composition-only specification. The large difference in crossover penetration reflects the flatness of B_K at high penetration. The crossover is a penetration threshold, not a date. Supplemental Appendix F provides the construction and sensitivities.

used to extend the capital curve is conservative on this margin; Supplemental Appendix F and Supplemental Appendix Table F.1 report the construction and sensitivities.

5.2 Implications for measurement.

Figure 3 summarizes the central result: the two biases evolve in opposite directions over the transition, while their effects on measured TFP are additive (Equation 10). Hence, the capital correction remains necessary but becomes insufficient as penetration rises and the output-value bias overtakes it.

Accounting differences complicate current cross-country comparisons. A system that still uses broad construction deflators records less capital deepening and more electricity TFP than the post-

2023 United States, even under identical technology. For every ten percentage points of renewable-capital exposure, the measured US deflator gap raises value-added TFP by about 0.6 percentage points per year using its smoothed 2010–2024 rate, and about 0.8 points using the larger recent rate. A US-anchored harmonization attributes 17–34 cumulative log points of the published EU–US Utilities gap over 2011–2024 and 3.3–8.5 log points of the Germany–US Section-D gap over 2010–2017 to the deflator convention. These ranges make some published rankings fragile, but do not establish a definitive reversal (Supplemental Appendix G). A closely related harmonisation strategy was used in the ICT literature, where differences in national computer deflators led researchers to impose common, often US-based, price indexes for international productivity comparisons (Wyckoff, 1995; Schreyer, 2000).

The statistical priorities follow directly. First, renewable capital should be deflated with capacity-specific cost indexes, following the post-2023 US treatment. Second, delivered electricity should not be divided into separate output products according to generation technology, because the market does not value otherwise identical MWh differently by source. Third, statistical agencies should begin constructing value-weighted electricity output that distinguishes delivery by time, location, and system state.

6 Conclusion

The energy transition reproduces the ICT measurement bias on the capital side but creates a distinct bias on the output side. The BEA's 2023 deflator revision shows that broad construction indexes overstated US electricity productivity growth by 2.8 log points over 2011–2024, or 4.3 log points on a value-added basis. It recorded falling renewable investment costs as productivity rather than capital deepening. Correct capital deflation removes this misclassification.

It does not, however, address the declining value of renewable generation as solar and wind deploy. Hourly evidence from European and US wholesale markets shows that wind and solar generation is increasingly concentrated in lower-value hours. As the energy transition unfolds and renewable energy becomes a larger share of electricity generation, the output-value bias becomes increasingly important and eventually overtakes the capital-price bias.

Productivity measurement in the energy transition therefore requires two distinct corrections. The United States has adopted the first, but others have not[3], creating a discrepancy on green productivity. None of the official statistical systems examined distinguishes electricity output by the hour and location of delivery, even though ESA 2010 recognizes time of delivery as a potential quality characteristic.

[3] As of August 2026.

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This supplemental appendix is organized to follow the paper. Appendix A documents the measurement and robustness of the capital-deflator reclassification (Section 3 of the paper). Appendix B calibrates the sourcing comparison of Section 3.3. Appendix C states the two aggregation disciplines behind the output-side analysis: electricity output is differentiated by the time and location of delivery, and not by generating technology. Appendix D documents where the output-value bias lives in official statistics. Appendix E contains the market-data measurement of the bias. Appendices F and G document the crossover calibration and the cross-country harmonization of Section 5. Appendix H presents storage as a second member of the self-correlated class, and Appendix I records the official-source documentation.

A The capital-deflator reclassification: measurement and robustness

This appendix explains how the capital-deflator reclassification in Table 1 is constructed. The empirical question is narrow: how much does measured capital-input growth change when the renewable assets are deflated by their capacity cost rather than by the broad electric-infrastructure index? The comparison holds nominal investment, output, labour, and intermediate inputs fixed. It therefore changes only the amount of real capital obtained from the same nominal investment.

The calculation proceeds in four steps. Section A.1 first explains why a comparison of published statistical vintages cannot isolate this effect. Section A.2 then defines the share of sector capital exposed to the deflator change and constructs the transparent net-stock benchmark in Table 1. Section A.3 replaces stock values with Hall–Jorgenson rental values. Finally, Section A.4 uses those rental values to construct capital-input growth under each deflator convention, derives the exact decomposition into the direct effect and the rental-weight response, and reports the relevant robustness checks. Subsequent sections check renewable exposure, the nominal investment base, the measured decline in capacity costs, and the timing of the correction.

A.1 Why the published-vintage difference does not identify the effect

The 2023 Comprehensive Update appears to offer a simple before-and-after test: BEA introduced the renewable-specific deflator in that update, so one might compare published Utilities productivity before and after it. That comparison does not isolate the deflator change because the update revised several parts of the production account at the same time.

The capital revision has the expected sign. A lower investment deflator converts the same nominal expenditure into more real capital, so measured capital input rises. Holding the other terms in the growth-accounting equation fixed, measured TFP should consequently fall. Figure A.1 instead shows that published TFP rises. The vintage difference is therefore not a deflator-only experiment.

Figure A.2 identifies the source of the discrepancy. The output revision is small, and the capital and labour revisions lower TFP. The intermediate-input block contributes about +7.0 log points and more than offsets them. That contribution is recovered as a residual, so it cannot be assigned to a particular intermediate input; moreover, NAICS 22 is broader than the NAICS 2211 electric-power account used in Table 1. The relevant conclusion is simply that the comprehensive update bundled several changes. This is why the paper instead applies both deflators to the same nominal investment flow and holds every other measured input fixed.

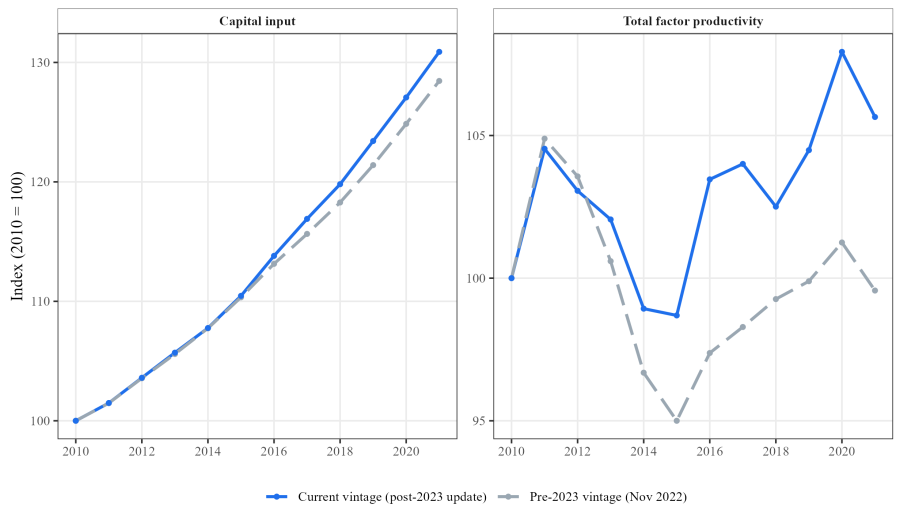

Figure A.1: **Why the 2023 vintage comparison does not identify the renewable-capital deflator effect.** US Utilities (NAICS 22), BLS–BEA KLEMS, 2011–2021 cumulative log growth (Bontadini et al., 2023). The grey long-dashed line reports the pre-2023 vintage and the blue solid line the current vintage. The update raised measured capital input by 1.9 log points, from 25.0 to 26.9, but also raised measured TFP by 5.9 log points, from −0.4 to 5.5. Because the deflator change by itself would raise capital input and lower TFP, the opposite movement in published TFP shows that other revisions dominate the vintage comparison.

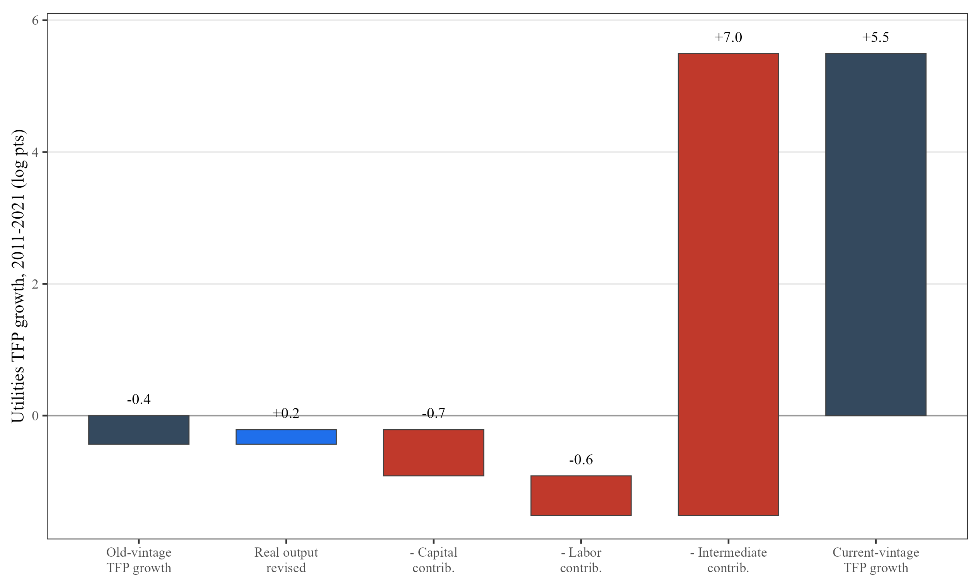

Figure A.2: **Decomposition of the 2023 Utilities TFP vintage revision.** US Utilities (NAICS 22), cumulative log growth over 2011–2021. Read from left to right, the revision moves TFP growth from −0.4 to +5.5 log points: +0.2 from output, −0.7 from capital, −0.6 from labour, and +7.0 from intermediate inputs. The capital contribution has the sign implied by the new deflator, but it is dominated by the intermediate-input revision.

A.2 Renewable-capital exposure and the net-stock benchmark

This subsection defines the exposure required by Equation (2) and distinguishes it from the observable measure used in the first column of Table 1. The distinction matters because a stock value asks how much an asset is worth, whereas a capital-services value asks how much of the sector's annual cost of using capital is attributable to that asset.

Let $\mathcal{A}$ denote all assets used in NAICS 2211 and let $\mathcal{R} \subset \mathcal{A}$ denote the assets whose deflator is changed (renewables), that we called "repriced assets". For asset a, let $K_{a,t}$ denote its real productive stock and $R_{a,t}$ its rental price. The exposure required by the capital-input formula is the repriced assets' share of sector capital services,

$$\omega_{R,t} = \frac{\sum_{a \in \mathcal{R}} R_{a,t} K_{a,t}}{\sum_{a \in \mathcal{A}} R_{a,t} K_{a,t}}. \tag{S.11}$$

The denominator covers all sector assets (structure, equipment, and intellectual property products) because the capital share in Equation (2) also covers all sector capital. A structures-only denominator would therefore be inconsistent with the factor share multiplying the exposure term.

Official data do not publish the rental values in Equation (S.11) at this asset detail. They do publish current-cost stocks, which give the observable proxy

$$\widetilde{\omega}_{R,t} = \frac{\sum_{a \in \mathcal{R}} P^K_{a,t} K_{a,t}}{\sum_{a \in \mathcal{A}} P^K_{a,t} K_{a,t}}, \tag{S.12}$$

where $P^K_{a,t} K_{a,t}$ is the current replacement-cost value of the stock. The numerator is BEA asset SU60, "alternative electric" structures. It contains wind and solar structures together with small dry-waste and geothermal components, matching the assets to which BEA applies the alternative-electric deflator. The denominator includes all NAICS 2211 structures, equipment, and intellectual property products. On this sector-wide base, $\widetilde{\omega}_{R,t}$ rises from 3.6 percent in 2011 to 11.2 percent in 2024. The corresponding structures-only ratio reaches 18.2 percent, but it is not used because it omits other assets that supply sector capital services.

What the net-stock column measures. The first column of Table 1 is deliberately simple. It uses arithmetic sample means for both the observable stock exposure and the sector capital share:

$$\widetilde{\omega}^*_R = \frac{1}{T} \sum_{t=2011}^{2024} \widetilde{\omega}_{R,t}, \qquad s^*_K = \frac{1}{T} \sum_{t=2011}^{2024} \bar{s}_{K,t}, \qquad T = 14, \tag{S.13}$$

where $\bar{s}_{K,t}$ is the standard two-period average of the current-price capital share. The resulting cumulative benchmark is

$$B_K^{\text{stock},*} = s^*_K \widetilde{\omega}^*_R \sum_{t=2011}^{2024} \gamma_{K,t}. \tag{S.14}$$

With $\widetilde{\omega}^*_R = 0.0724$ and $\sum_t \gamma_{K,t} = 1.1931$, the exposure-adjusted capital wedge is 0.0864, or 8.64 log points. Multiplying by the mean gross-output capital share, $s_K^{\text{GO},*} = 0.4977$, gives 4.30 log points. The corresponding mean value-added share, $s_K^{\text{VA},*} = 0.7793$, gives 6.73 log points.

For the TFP levels in Panel B, all factor shares in this benchmark are held at their arithmetic sample means. Within the net-stock benchmark, annual factor shares are replaced by their 2011–2024 arithmetic means and these same fixed shares are used under both deflators. Output,

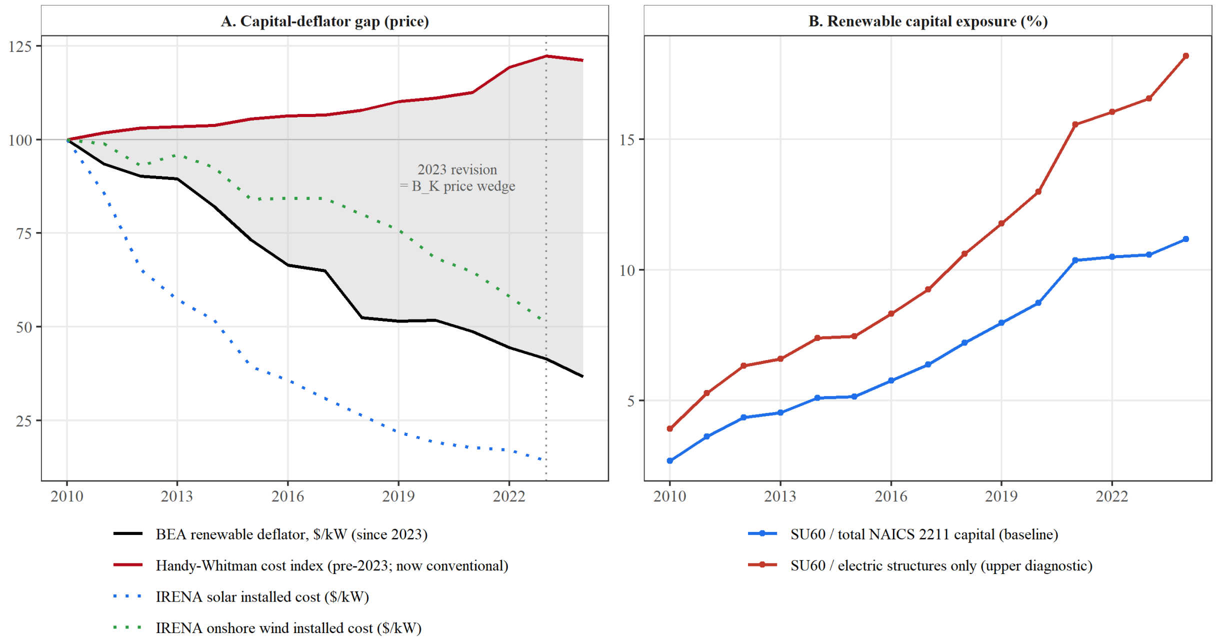

Figure A.3: **The price and exposure components of the capital reclassification.** *Panel A* compares the renewable-specific capacity-cost deflator introduced in the 2023 Comprehensive Update with the broad Handy–Whitman construction index previously applied to alternative-electric structures. The shaded difference is the deflator gap γ_K; IRENA solar and onshore-wind installed costs provide external comparisons. All price series are relative to the GDP deflator and indexed to $2010 = 100$. *Panel B* reports the current-cost stock exposure in Equation (S.12), measured against total NAICS 2211 capital.

labour, intermediate inputs, and their weights are identical across the two residuals; only measured capital-input growth changes. Hence,

$$\widehat{A}^{\text{broad},*} - \widehat{A}^{\text{capacity},*} = s_K^* \left(\widehat{K}^{\text{capacity}} - \widehat{K}^{\text{broad}} \right).$$

They are $+3.6$ and -0.7 gross-output log points, and $+4.68$ and -2.05 value-added log points. Their differences are the 4.30 and 6.73 log-point corrections above, up to displayed rounding. This account is useful because every input is directly auditable from published series. It is a comparison benchmark, not the preferred measure of capital input.

Note that labour-productivity growth can be decomposed into TFP growth and capital deepening:

$$\widehat{Y/L} = \widehat{A} + s_K, \widehat{K/L},$$

where s_K is capital's income share. Thus, a correction to the capital deflator that reallocates measured growth from TFP to capital deepening does not reduce measured labour-productivity growth itself; it changes only the channel through which that growth is attributed. Both higher TFP and a higher capital stock per worker can raise output per worker and, under competitive factor pricing, real wages.

A.3 Constructing rental values

The preferred account asks how much service each asset supplies during the year, not only how much its stock is worth. The Hall–Jorgenson rental price answers that question: it is the annual cost of tying up funds in the asset, replacing the part that wears out, and accounting for the gain or loss from a change in the asset's price (Hall and Jorgenson, 1967; OECD, 2009).

For asset a, define own-price inflation as $\pi_{a,t} = \Delta \ln P^K_{a,t}$ and let δ_a denote geometric depreciation. The ex-post rental price is

$$R^{\text{raw}}_{a,t} = P^K_{a,t}\left(r_t + \delta_a - \pi_{a,t}\right). \tag{S.15}$$

Note that the value of $R^{\text{raw}}_{a,t}$ can be negative, I deal with it with nonnegative-weight restriction described below.

The three terms inside parentheses are the required return, depreciation, and the holding loss. A falling asset price makes $\pi_{a,t} < 0$, so the capital-loss term $-\pi_{a,t}$ raises its rental price, holding the required return and depreciation fixed. Asset-price inflation $\pi_{a,t}$ is indeed the only component that varies both across assets and over time. If its price falls faster than those of other assets, its rental value rises relative to theirs and its normalized capital-services weight changes. This is the key reason the deflator affects rental weights as well as measured real asset growth. Equation (S.15) is the continuous-time form of the standard discrete user-cost formula.

Closing the rental account. The rate of return r_t is not chosen to obtain a particular exposure. It is solved separately in each year so that the raw rental values sum to measured sector capital income. Let $\Pi_t \equiv$ value added$_t$ − labour compensation$_t$ be the capital income. The identifying condition is

$$\Pi_t = \sum_{a\in\mathcal{A}} P^K_{a,t} K_{a,t}\left(r_t + \delta_a - \pi_{a,t}\right). \tag{S.16}$$

Solving this identity gives

$$r_t = \frac{\Pi_t - \sum_{a\in\mathcal{A}} P^K_{a,t} K_{a,t}\left(\delta_a - \pi_{a,t}\right)}{\sum_{a\in\mathcal{A}} P^K_{a,t} K_{a,t}}. \tag{S.17}$$

Thus, observed capital income determines the overall return, while depreciation and asset-price changes determine how that income is allocated across assets. The endogenous return averages 8.3% over 2011–2024.

From rental values to weights. The Törnqvist aggregation requires the asset-level capital-services weights $v_{a,t}$ to be nonnegative. Because a negative rental rate would produce a negative rental value and hence a negative $v_{a,t}$, I impose a lower bound on the net rental rate as

$$\rho_{a,t} = \max\{r_t + \delta_a - \pi_{a,t},\, 0.005\}, \qquad R_{a,t} = P^K_{a,t}\rho_{a,t}, \tag{S.18}$$

and normalize each asset's rental value to obtain

$$v_{a,t} = \frac{R_{a,t}K_{a,t}}{\sum_{b\in\mathcal{A}} R_{b,t}K_{b,t}}. \tag{S.19}$$

Each $v_{a,t}$ is therefore the asset's share of the sector's annual rental value of capital. The floor is applied only after Equation (S.17) is solved: the raw user costs satisfy the capital-income identity, and the floor changes only the weights used for aggregation. Section A.4 reports how much this restriction matters.

Depreciation inputs. I hold asset-specific depreciation rates fixed over the sample. For equipment, conventional structures, and intellectual property products, I use the 2024 BEA implied rates for NAICS 2211,

$$\delta_{\text{equipment}} = 0.0645, \quad \delta_{\text{conventional structures}} = 0.0236, \quad \delta_{\text{IPP}} = 0.3880. \tag{S.20}$$

Conventional structures are total structures less SU60. BEA does not report a separate NAICS 2211 implied rate for SU60. I therefore derive $\delta_{\text{SU60}} = 0.0303$ from BEA's declining-balance parameter of 0.909 and 30-year service life (Bureau of Economic Analysis, nda, p. 10),

$$\delta_{\text{SU60}} = 0.0303$$

The robustness analysis varies this less precisely established rate over $[0.025, 0.060]$ and repeats the full capital-services calculation.

A.4 Capital-services aggregation and the exact reclassification

This subsection connects the rental construction to the preferred numbers in Table 1. There are two effects to keep separate that I detail below, i) repricing SU60 directly raises its measured real growth, ii) It also changes changes the rental weights used to aggregate all assets. The preferred account includes both.

Let $j \in \{\text{capacity}, \text{broad}\}$ denote the deflator convention, let $\widehat{K}^j_{a,t} \equiv \Delta \ln K^j_{a,t}$, and define the two-period average rental weight

$$\bar{v}^j_{a,t} = \frac{1}{2}\left(v^j_{a,t-1} + v^j_{a,t}\right). \tag{S.21}$$

The same weights provide the two objects needed for the calculation: summing the weights on the repriced assets $\mathcal{R}$ measures renewable exposure, while applying all the weights (all of $\mathcal{A}$) to asset growth measures sector capital-input growth,

$$\bar{\omega}^j_{R,t} = \sum_{a \in \mathcal{R}} \bar{v}^j_{a,t}, \qquad \widehat{K}^j_{E,t} = \sum_{a \in \mathcal{A}} \bar{v}^j_{a,t} \widehat{K}^j_{a,t}. \tag{S.22}$$

The first expression selects the renewable part of capital services; the second uses the entire asset distribution to construct the Törnqvist capital-input index.

The sector capital share is computed from nominal current-price payments, so it is identical under the two deflator conventions. It may nevertheless vary over time. Let $\bar{s}_{K,t}$ denote its two-period average. The preferred annual TFP reclassification is the difference between the two capital-input indexes, multiplied by that common share:

$$B^{\text{services}}_{K,t} = \bar{s}_{K,t}\left(\widehat{K}^{\text{capacity}}_{E,t} - \widehat{K}^{\text{broad}}_{E,t}\right). \tag{S.23}$$

Equation (S.23) is the formula used for the total preferred B_K in Panel B of Table 1. Thus, the two rows of that panel differ in their treatment of factor shares: the net-stock benchmark uses sample means, whereas the preferred account uses the annual two-period shares.

Separating the two effects. To show how Equation (S.23) relates to the direct formula in Equation (2), add and subtract broad-deflator asset growth evaluated at the capacity-cost weights,

$$\begin{aligned}\widehat{K}^{\text{capacity}}_{E,t} - \widehat{K}^{\text{broad}}_{E,t} = &\sum_{a \in \mathcal{A}} \bar{v}^{\text{capacity}}_{a,t}\left(\widehat{K}^{\text{capacity}}_{a,t} - \widehat{K}^{\text{broad}}_{a,t}\right) \\ &+ \sum_{a \in \mathcal{A}}\left(\bar{v}^{\text{capacity}}_{a,t} - \bar{v}^{\text{broad}}_{a,t}\right)\widehat{K}^{\text{broad}}_{a,t}.\end{aligned} \tag{S.24}$$

Only the assets in $\mathcal{R}$ are repriced. Because nominal investment is the same under both conventions, their measured real growth differs by the deflator gap:

$$\widehat{K}_{a,t}^{\text{capacity}} - \widehat{K}_{a,t}^{\text{broad}} = \begin{cases} \gamma_{K,t}, & a \in \mathcal{R}, \\ 0, & a \notin \mathcal{R}. \end{cases} \tag{S.25}$$

Substituting Equation (S.25) into Equation (S.24), and then multiplying by the capital share, gives the exact decomposition

$$B_{K,t}^{\text{services}} = \bar{s}_{K,t} \left[\underbrace{\bar{\omega}_{R,t}^{\text{capacity}} \gamma_{K,t}}_{\text{direct deflator effect}} + \underbrace{\sum_{a \in \mathcal{A}} \left(\bar{v}_{a,t}^{\text{capacity}} - \bar{v}_{a,t}^{\text{broad}} \right) \widehat{K}_{a,t}^{\text{broad}}}_{\text{rental-weight response}} \right]. \tag{S.26}$$

The first term is the main-text exposure formula evaluated with the capacity-cost rental weights used in the preferred index. The superscript "capacity" is necessary because the weights are recomputed under each deflator. The second term records the resulting change in aggregation weights; it runs over all assets because the weights are normalized to sum to one. Using the broad weights as the reference would give a different split between these two terms but exactly the same total in Equation (S.23).

Equation (2) is recovered when the weights do not respond to the deflator convention. If

$$\bar{v}_{a,t}^{\text{capacity}} = \bar{v}_{a,t}^{\text{broad}} \qquad \text{for every } a, \tag{S.27}$$

the second term in Equation (S.26) is zero, and the first term gives

$$B_{K,t}^{\text{services}} = \bar{s}_{K,t} \bar{\omega}_{R,t} \gamma_{K,t}. \tag{S.28}$$

The weights may still change over time; the restriction is only that changing the deflator does not change them within the same year. This is the precise sense in which the direct formula is the fixed-weight special case of the preferred capital-services account.

Mapping the decomposition to Table 1. The two-period rental exposure rises from 0.013 in 2011 to 0.114 in 2024. It is not monotone: its sample maximum, 0.126, occurs in 2023. Summing the annual products $\bar{\omega}_{R,t}^{\text{cap}} \gamma_{K,t}$ over 2011–2024 gives the 6.81-log-point capital wedge reported for the preferred account in Panel A of Table 1.

The 8.64 figure in the adjacent column is not built the same way. It is the mean stock exposure times the cumulative deflator gap, $\widetilde{\omega}_R^* \sum_t \gamma_{K,t}$, which is what makes the benchmark reproducible by hand, whereas 6.81 is a sum of annual products. The two Panel A wedges therefore differ in timing as well as in the exposure concept: applied annually, the stock exposure would give $\sum_t \widetilde{\omega}_{R,t} \gamma_{K,t} = 9.02$ log points. Table A.1 separates the two effects, after multiplying through by the capital share ($s_K^* = 0.498$, hence the direct effect in the Benchmark row, with mean exposure and share, is $4.30 = 8.64 \times 0.498$).

Table A.1 separates the reasons the benchmark and the preferred account differ. Applying the same stock exposure and capital share annually rather than at their means raises the direct effect, because the deflator gap is concentrated in later years when both are higher. Replacing stock with rental exposure is the largest single step; the two-period Törnqvist weights used in the index account for a further fifth of a log point. The rental-weight response then carries the direct effect to the preferred total.

Table A.1: **From the transparent benchmark to the preferred capital-input bias.** NAICS 2211, cumulative 2011–2024 log points. Rows marked ⋆ are the two direct effects reported in Panel A of Table 1; the final row is the preferred total B_K in Panel B.

	Gross output		Value added	
	Change	Level	Change	Level
Benchmark: mean exposure and share⋆	—	4.30	—	6.73
exposure and share applied annually	+0.34	4.64	+0.37	7.10
rental rather than stock exposure	−0.92	3.72	−1.45	5.65
two-period Törnqvist weights	−0.20	3.52	−0.28	5.37
Preferred direct effect⋆		**3.52**		**5.37**
rental-weight response	−0.72	2.81	−1.03	4.33
Preferred total B_K		**2.81**		**4.33**

The gross-output direct effect makes the bridge between the two columns explicit. The constant-mean stock benchmark of 4.30 rises to 4.64 when the stock exposure and the capital share are applied annually, because the deflator gap is concentrated in later years, when both are higher. Replacing annual stock exposure with annual rental exposure lowers the figure by 0.92, to 3.72, and the two-period Törnqvist averaging used in the preferred index lowers it by a further 0.20, giving 3.52. The two columns of Panel A therefore differ for three reasons: constant-mean rather than annual application, rental rather than stock exposure, and two-period rather than contemporaneous weights.

Using common Törnqvist timing and the annual capital shares gives

$$\begin{aligned} B_K^{\mathrm{GO}} &= \underbrace{3.523}_{\text{direct}} + \underbrace{(-0.717)}_{\text{rental-weight response}} = \underbrace{2.806}_{\text{total}}, \\ B_K^{\mathrm{VA}} &= \underbrace{5.367}_{\text{direct}} + \underbrace{(-1.033)}_{\text{rental-weight response}} = \underbrace{4.334}_{\text{total}}. \end{aligned} \tag{S.29}$$

The negative response means that recomputing rental weights partly offsets the direct effect; it does not reverse it. These totals move gross-output TFP from −0.3 to −3.1 log points and value-added TFP from −0.7 to −5.0 log points. The stock benchmark and the preferred account answer the same question but use different capital-input constructions: the first is transparent and reproducible from published stock values, while the second is the conceptually appropriate services measure.

A.4.1 The nonnegative-rental-weight restriction

This check asks whether the preferred result is created by the 0.005 floor in Equation (S.18). A raw ex-post rental rate becomes negative when measured asset-price inflation exceeds the required return plus depreciation. Such a value would give the asset a negative weight in the Törnqvist index, so the preferred account imposes a nonnegative lower bound.

The restriction binds only for SU60 over 2011–2024: once under the capacity-cost convention and six times under the broad convention. The minimum raw net rental rates are −0.019 and −0.182, respectively. The asymmetry follows directly from the two price paths. Under capacity-cost deflation, a falling SU60 price is a holding loss and raises its user cost. Under the broad deflator, measured SU60 price growth is much higher, so the holding-gain term lowers its user cost and more often pushes it below zero.

Table A.2: **Sensitivity to the rental-rate floor.** Cumulative 2011–2024 log points.

Floor	Capital-input bias B_K		Capacity-cost TFP		Observations changed
	Gross output	Value added	Gross output	Value added	
None; raw weights	1.93	3.02	−3.02	−4.92	0
0	2.75	4.25	−3.07	−5.00	7
0.001	2.76	4.27	−3.07	−5.00	7
0.005 (preferred)	**2.81**	**4.33**	**−3.08**	**−5.02**	7
0.010	2.86	4.42	−3.10	−5.04	8
0.020	2.97	4.57	−3.12	−5.07	9
0.030	3.07	4.72	−3.16	−5.13	12

Notes: "None" passes raw rental rates through unchanged and therefore admits seven negative asset-year weights; "0" replaces those values with zero. The final column counts observations altered by the stated floor relative to raw rental rates. All calculations (28, 14 years x 2 deflators) first solve the capital-income closure in Equation (S.16) and then impose the floor.

Across nonnegative floors from zero to 0.030, gross-output B_K ranges only from 2.75 to 3.07 log points. The raw calculation is discontinuous from this range because it admits negative rather than zero weights; it lowers B_K to 1.93. That change falls mainly on the broad-deflator counterfactual, where six of the seven negative observations occur. Relative to the preferred floor, removing the restriction changes capacity-cost gross-output TFP by only 0.06 log points but changes the broad-minus-capacity comparison by 0.88. The raw result is therefore informative about the restriction's quantitative role, but it is not an alternative capital-services index with economically meaningful weights.

A.4.2 Depreciation, the rate of return, and the sample endpoint

The remaining checks address two possible sources of sensitivity. The first is the user-cost construction: SU60 depreciation is the least precisely measured depreciation input, while the preferred rate of return is obtained from the annual capital-income closure rather than imposed externally. The second is the sample endpoint, because the 2024 capacity-cost observation is provisional.

Table A.3 separates the first issue into its two parts. It varies SU60 depreciation and replaces the annual endogenous return with a fixed return applied to every asset and both deflator conventions. The OECD capital-measurement framework treats such an exogenous return as a standard alternative to the endogenous approach and reports long-run real-return calibrations between 3 and 5 percent across countries (OECD, 2009, pp. 138–140). Because the present user-cost formula pairs r with nominal asset-price inflation, the 0.03 and 0.05 columns should be read as deliberately low return cases rather than as exact real-to-nominal conversions. The 0.083 column fixes the return at the sample mean of the preferred endogenous series, and 0.11 provides a high-return stress case.

What changes the reclassification. Across the grid, gross-output B_K ranges from 2.36 to 4.08 log points and remains positive. The two parameters have markedly different effects. At the BEA depreciation rate, raising the fixed return from 0.03 to 0.11 changes B_K by 0.31 log points. At the return closest to the endogenous mean, raising δ_{SU60} from 0.025 to 0.060 changes it by 1.07 log points. SU60 depreciation is therefore the more important parameter for the reclassification.

What changes the level of TFP. The return matters more for measured productivity itself. At the BEA depreciation rate, capacity-cost TFP ranges from −6.63 when $r = 0.03$ to −2.75 when

Table A.3: **Sensitivity to the rate of return and renewable depreciation.** NAICS 2211, cumulative 2011–2024 gross-output log points.

	Capital-input reclassification B_K				Capacity-cost TFP			
δ_{SU60}	r=0.03	r=0.05	r=0.083	r=0.11	r=0.03	r=0.05	r=0.083	r=0.11
0.025	2.36	2.44	2.60	2.76	−6.39	−4.72	−3.09	−2.62
0.0303 (BEA baseline)	2.58	2.66	**2.75**	2.89	−6.63	−4.93	**−3.24**	−2.75
0.040	3.00	3.07	3.06	3.13	−7.06	−5.32	−3.55	−3.00
0.060	4.08	3.90	3.67	3.60	−8.08	−6.14	−4.18	−3.49

Notes: Each column holds r fixed across years, assets, and deflator conventions. The preferred account instead solves r_t annually from Equation (S.17); its mean is 0.083 and it yields $B_K = 2.81$ and capacity-cost TFP of −3.08. The bold entries are the fixed-return counterparts at that mean and the BEA depreciation rate. All entries use the preferred 0.005 rental-rate floor.

$r = 0.11$. A higher return increases the common component of every asset's net rental rate. Asset-specific depreciation and capital gains then matter less for the relative rental weights, which move toward current-cost stock shares and change the level of the capital-services index. By contrast, B_K is the difference between two indexes constructed with the same fixed return, so most of this level effect cancels. The return convention is consequently important for the measured level of TFP but much less important for the reclassification studied here.

Excluding the provisional endpoint. Finally, the 2024 capacity-cost observation is provisional and accounts for 9.7 of the 66.5 log-point decline in that deflator. Ending the calculation in 2023 reduces the cumulative deflator gap from 119.3 to 108.1 log points and lowers the preferred reclassification from 2.81 to 2.4 gross-output log points and from 4.33 to 3.7 value-added log points. Recomputing the complete 2011–2023 accounts gives capacity-cost TFP of −2.2 gross-output and −3.8 value-added log points. The detailed comparison with independent installed-cost series is reported in Section A.6.

Taken together, these checks delimit the claim. The exact size of the correction depends on the capital-services construction, and the rental-weight response is not negligible. Its sign, however, survives the stock-versus-services choice, the rental-rate floor, the return convention, and the exclusion of 2024. Under every reported construction, capacity-cost deflation shifts measured growth out of TFP and into capital deepening.

NEW

A.5 Exposure sensitivity and nominal-investment stability

This subsection reports two separate checks on the capital correction. First, I stress-test renewable exposure, ω_R, which determines the weight placed on the repriced assets. It asks how much the result changes if renewable exposure is measured differently Second, I test the stability of the nominal investment base by comparing total nominal investment in electric structures across BEA vintages. This comparison shows whether BEA revised the dollars being deflated when it introduced the new price index.

Sensitivity to renewable exposure. Because the direct B_K is proportional to renewable exposure, I stress-test ω_R by ± 10 percent. Gross-output B_K moves by about ± 0.5 log points in the stock-based account and ± 0.3 in the preferred capital-services account. A plausible error in renewable exposure cannot overturn the result, and leave the sign unchanged.

Did the update change nominal investment? The second check asks whether the two deflators are being applied to a stable nominal series. Over the common 2011–2021 window, cumulative nominal investment in electric structures is \$792.6 billion in the current vintage and \$796.8 billion in the September 2022 vintage, a revision of only -0.5 percent. Nine of the eleven annual observations are unchanged, and the largest annual revision is 4.5 percent in 2021.

Note that this check has a narrower purpose than the vintage comparison in Section A.1. Here the question is only whether the nominal investment flow underlying the deflator experiment changed materially. As it did not, the broad and capacity-cost deflators can therefore be applied to effectively the same nominal investment base.

A.6 Does the changing wind–solar mix explain the fall in \$/kW?

The BEA alternative-electric deflator is a chained Fisher price index. A pure shift in investment between wind and solar therefore cannot lower the index if the prices of both technologies are unchanged. This subsection addresses the separate empirical question of whether the measured decline is corroborated by independent installed-cost data. I construct a comparable chained index from LBNL data and contrast it with raw average \$/kW, which can move when the wind–solar mix changes. These comparisons validate the price decline; they do not enter the construction of γ_K or B_K.

Comparable windows. The BEA deflator is observed from 2010 through 2024. For external validation, the preferred comparison ends in 2023 because the 2024 observations are provisional in both the BEA and LBNL data. The shorter EIA series is available only for 2018–2024. The global IRENA comparison uses 2010–2023. The endpoint check in Section A.4.2 shows separately that excluding the provisional 2024 observation does not change the sign of the capital reclassification.

Constructing a like-for-like comparison. Independent U.S. series on installed costs per kilowatt for utility-scale solar and land-based wind are published by Lawrence Berkeley National Laboratory (LBNL) in its annual market reports (Seel et al., 2025; Wiser et al., 2025). Solar capacity can be measured on a direct-current (DC) basis, using the nameplate capacity of the photovoltaic modules before conversion, or on an alternating-current (AC) basis, using the inverter-limited capacity after conversion. LBNL reports installed costs on both bases but reports the capacity additions used here only in MW-AC. The BEA deflator is built from those EIA data, whose records utility-scale capacity which are expressed AC terms. I therefore construct the benchmark on the observed AC basis. The DC specification uses LBNL's \$/W-DC costs and inferred DC capacity and is reported only as a capacity-basis sensitivity. Let $p_{j,t}$ and $q_{j,t}$ denote installed cost per kilowatt and new capacity for technology $j \in \{\text{solar}, \text{wind}\}$. I aggregate the two price series with a chained Törnqvist index,$\bar{s}_{j,t}$ is technology j's two-period average expenditure share,

$$\Delta \ln P_t^{\text{chain}} = \sum_j \bar{s}_{j,t} \, \Delta \ln p_{j,t}.$$

Like the BEA Fisher index, the Törnqvist index cannot move when quantities shift at unchanged technology-specific prices. This is a well known property of chained index.[4]

For reference, I also calculate average expenditure per kilowatt,

$$V_t = \frac{\sum_j p_{j,t} q_{j,t}}{\sum_j q_{j,t}},$$

which can change solely because the wind–solar mix changes. In Table A.4, the difference between the change in average \$/kW and the chained price change is labelled the mix contribution. A positive value means that the changing mix raised average \$/kW relative to the chained price path; a negative value means that it lowered it. This decomposition is reported only to interpret the independent LBNL data.

Comparison with an independent U.S. price series. The resulting LBNL index tracks the BEA alternative-electric deflator closely through 2023, while the broad Handy–Whitman plant index rises (Figure A.4). On the nominal basis used in Table A.4, the BEA and LBNL indexes fall by 56.8 and 53.0 log points over 2010–2023, a difference of only 3.8 log points. The much larger gap through 2024 reflects the provisional final observation: the BEA index falls sharply while the LBNL series rises slightly. The close agreement over 2011-2023 therefore provides independent support for both the direction and approximate magnitude of the BEA capacity-cost decline. The 2024 divergence is treated as endpoint uncertainty in Section A.4.2; it does not overturn the earlier agreement. The construction and adoption of the BEA deflator are documented in Section I.

What the U.S. decomposition shows. On the directly comparable AC basis, the LBNL chained price falls by 53.0 log points over 2010–2023, close to the 56.8-log-point BEA decline. The mix contribution is +21.1 log points. Thus, the shift between wind and solar made average \$/kW fall less than the underlying within-technology price index, meaning that the mix shift did not produce the measured price decline.

The DC rows ask whether the conclusion depends on measuring solar capacity by module capacity rather than inverter output. This change increases measured solar capacity, especially late in the sample when solar is a large share of additions. It therefore has a large effect on average

[4] A chained price index moves only with prices, never with the quantity mix. The Fisher index BEA uses is $P_t^F = \left(P_t^L \, P_t^P\right)^{1/2}$, with $P_t^L = \dfrac{\sum_j p_{jt} q_{j,t-1}}{\sum_j p_{j,t-1} q_{j,t-1}}$ and $P_t^P = \dfrac{\sum_j p_{jt} q_{jt}}{\sum_j p_{j,t-1} q_{jt}}$; under constant prices $p_{jt} = p_{j,t-1}$ every summand of each numerator equals its denominator counterpart, so $P_t^L = P_t^P = 1$ and hence $P_t^F = 1$ for *any* quantities q—the mix cannot move it (the identity test). The Törnqvist index satisfies the same property transparently: $\Delta \ln P_t = \sum_j \bar{s}_{jt} \, \Delta \ln p_{jt}$, with expenditure-share weights $\bar{s}_{jt} = \frac{1}{2}(s_{jt} + s_{j,t-1})$ and $s_{jt} = p_{jt} q_{jt} / \sum_k p_{kt} q_{kt}$; a pure composition shift moves the quantities q_{jt}—hence the shares—at unchanged prices, so $\Delta \ln p_{jt} = 0$ for every j and $\Delta \ln P_t = 0$ whatever the mix, with chaining ($\ln P_T = \sum_t \Delta \ln P_t$) preserving this. The shares enter only as weights on price changes. By contrast the capacity-weighted unit value $V_t = \sum_j p_{jt} q_{jt} \big/ \sum_j q_{jt}$ has $\Delta \ln V_t \neq 0$ under the same shift; the residual $\Delta \ln V - \Delta \ln P$ is exactly the composition (unit-value) bias. That residual is the object decomposed below, and the expenditure-share weighting is what makes the two capacity bases comparable.

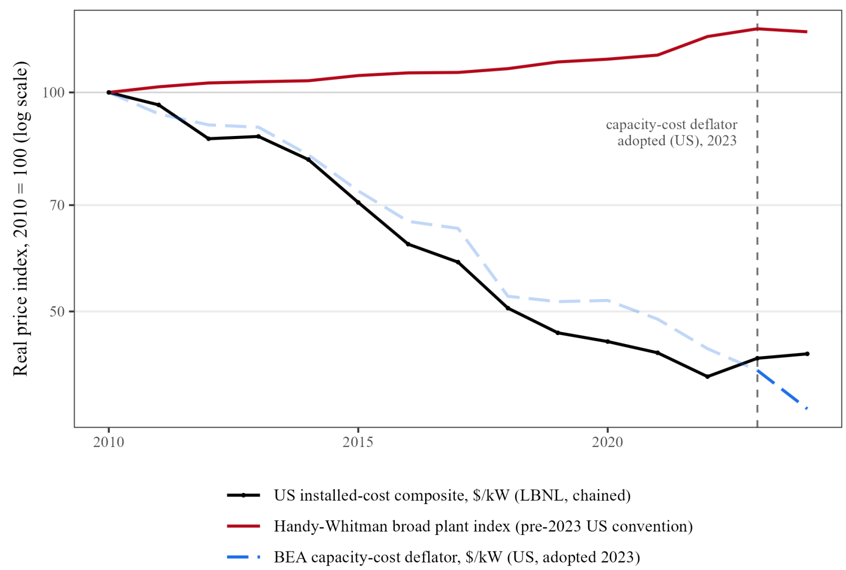

Figure A.4: **The BEA capacity-cost deflator tracks an independent U.S. installed-cost index.** LBNL utility-scale solar and land-based wind installed costs, aggregated with a chained Törnqvist index (black); the BEA alternative-electric deflator (blue, faded before its adoption in 2023); and the broad Handy–Whitman electric-plant index used previously (red). The figure expresses all three series relative to the GDP price index and sets 2010 to 100. The nominal BEA–LBNL difference reported in the text is unchanged by this common deflation. The 2024 divergence reflects a provisional BEA decline not yet matched in the LBNL data.

Table A.4: **Separating within-technology prices from the changing wind–solar mix.** U.S. utility-scale solar and land-based wind installed costs, cumulative log points.

		Within technology		Wind–solar composite			BEA comparison	
Capacity basis	Window	Solar	Wind	Chained price	Mix contribution	Average $/kW	BEA	BEA − chained
AC	2010–2023	−99.8	−19.0	−53.0	+21.1	−31.8	−56.8	−3.8
AC	2010–2024	−96.1	−14.7	−49.1	+19.2	−29.9	−66.5	−17.4
DC	2010–2023	−108.5	−19.0	−55.1	+2.9	−52.3	−56.8	−1.7
DC	2010–2024	−105.2	−14.7	−51.6	−2.5	−54.1	−66.5	−14.9

Notes: Nominal cumulative log points. LBNL reports installed costs in real 2024 dollars; I convert them to nominal dollars with the BEA GDP price deflator before comparison with the nominal BEA investment deflator. The mix contribution is average $/kW minus the chained price; the final column is the BEA change minus the chained price. Components may not add exactly at the displayed precision. LBNL reports solar additions in MW-AC. For the DC rows, DC capacity is inferred as $q_s^{DC} = q_s^{AC}\widehat{\mathrm{ILR}}$, where $\widehat{\mathrm{ILR}} = p_s^{AC}/p_s^{DC}$ is the implied inverter loading ratio. This rescaling preserves solar expenditure and therefore the expenditure weights. The DC rows are an alternative capacity basis, not an independent data source. The 2024 observations are provisional.

$/kW but only a small effect on the chained price: the settled-window decline changes from −53.0 to −55.1 log points. The DC construction is a rescaling of the same projects, not independent evidence. Even so, its settled-window mix contribution remains positive at +2.9 log points. With the provisional 2024 observation included, it becomes −2.5 log points, less than 5 percent of the 51.6-log-point chained decline. The conclusion therefore does not depend on the capacity basis.

Checks with other cost data. Two additional comparisons lead to the same conclusion. The EIA generator-cost available data begin only in 2018, so they cannot validate the full 2010–2023 decline. Over 2018–2024, a period dominated by the post-2021 cost increase, their wind–solar composite rises by 17.0 log points: 11.1 points come from within-technology price increases and 5.9 from the changing mix. The mix is therefore not the main component even over this shorter different window.

IRENA provides a longer global check. Over 2010–2023, its installed-cost series fall by 194.7 log points for solar and 67.2 for onshore wind. Holding technology shares fixed gives a composite decline between 131.0 log points under equal wind–solar weights and 180.0 log points when solar receives its 2024 U.S. share of capacity additions. Because these are global rather than U.S. data, they are less directly comparable than the LBNL evidence. They nevertheless show that within-technology declines alone are more than large enough to explain the BEA price decline.

A.7 Subperiod composition of the reclassification

Table 1 reports the accounting bridge from the apparent to the corrected productivity record over the full 2011–2024 window. This subsection asks when within the deployment decade that reclassification accrues. Because $B_K = \sum_t s_{K,t}\,\omega_{R,t}\,\gamma_{K,t}$ is a sum of annual terms, any partition of the window is additive: the 2011–2017 and 2018–2024 subperiods sum exactly to the full-period figure under each construction, with no interaction term to allocate.

The reclassification is concentrated in the second half. Under the preferred capital-services construction, 1.6 of the 2.8 cumulative gross-output log points—57%—accrue over 2018–2024, against 1.2 over the first seven years; on a value-added basis the corresponding split is 2.4 against 2.0. Under the two stock-based accounts the concentration is stronger, at roughly three quarters of the cumulative correction in the later window on both bases. The later concentration reflects the timing of exposure rather than a trend in the price gap. Renewable exposure, $\widetilde{\omega}_{R,t}$, roughly triples from 3.6 percent of NAICS 2211 capital in 2011 to 11.2 percent in 2024 and first exceeds its sample mean in 2019. By contrast, the annual deflator gap, $\gamma_{K,t}$, is volatile but shows no trend, ranging from 0.5 log points in 2020 to 22.7 in 2018. Because years of above-average exposure also tend to carry sizeable gaps, $\sum_t \widetilde{\omega}_{R,t}\gamma_{K,t}$ exceeds the value obtained by applying sample-mean exposure to every annual gap. Relative to that benchmark, 2021–2024 contributes +1.5 log points to the difference, whereas 2011–2016 contributes −1.1 log points. The deflator convention therefore matters little for the early 2010s and substantially for the years since 2018.

B Sourcing, local learning, and the net productivity comparison

This appendix calibrates both sides of the sourcing comparison of Section 3.3: the compression of measured electricity-sector TFP when renewable capital is repriced on a local rather than a global learning curve, Equation (8), and the manufacturing TFP generated by the additional domestic production associated with reshoring. Throughout, prices follow experience curves: a technology's installed cost falls by b_j log points per log point of cumulative experience, equivalently by

$$1 - 2^{-b_j}$$

per doubling. The elasticities are measured below.

Common experience stock and global descent. Let $Q_{j,0}$ denote the effective cumulative experience stock inherited in 2011 for technology j, common to domestic and foreign producers.

The renewable capacity-cost index declined by 66.5 log points over 2011–2024; the construction below attributes that descent to the growth of global cumulative capacity in the two technologies separately, and the local-only counterfactual then replaces global with domestic experience while leaving the inherited stock unchanged.

Two technologies. The paper considers a composite renewable good, however I calibrate a learning curve for each technology. Indeed, each technology has different characteristics: global solar cumulative capacity grew forty-five-fold over the window and global wind that grew six-fold, with learning elasticities that differ by a factor of three. For technology $j \in \{s, w\}$, let m_j be the growth of global cumulative capacity over 2011–2024, $s_{d,j}$ country d's share of global additions of that technology, and b_j the elasticity of the *domestic installed cost* with respect to global experience. The local-only counterfactual D_d^{re} and the global curve D_g are

$$D_d^{\mathrm{re}} = \sum_j w_j \, b_j \ln\bigl(1 + (m_j - 1)s_{d,j}\bigr), \qquad D_g = \sum_j w_j \, b_j \ln m_j, \tag{S.30}$$

with w_j the technology weight in the composite renewable index.

what is D exactly ?

The elasticities are measured on the object the deflator prices. Within-technology US installed costs fell 96.1 log points for utility-scale solar and 14.7 for land-based wind over 2010–2024 (Table A.4), against global capacity growth of 45.5 and 6.3 times, giving $b_s = 0.252$ and $b_w = 0.080$. These sit well below the corresponding *global* technology rates—IRENA reports installed-cost learning rates near 34% for solar and 25% for onshore wind (International Renewable Energy Agency, 2025, Table 1.1 and Box 1.8), and Way et al. (2022) report an experience exponent of 0.319 for solar-PV LCOE against cumulative electricity generated, not modules or installed capacity—and that gap is the object of this appendix. Equipment rides the global curve, but only about half of the global descent reaches US installed cost; the remainder accrues abroad, or to soft costs, labour and interconnection that do not ride the curve at all. This is also why the global rates cannot be used directly here: applied to a US index they would imply a descent of 142 to 182 log points against the 66.5 observed. The solar weight $w_s = 0.636$ is the single free parameter, pinned so that Equation (S.30) reproduces the measured composite descent; the independent check on the construction is that a chained index of the two US cost series tracks the BEA deflator to within 2 to 4 log points over 2010–2023 (Figure A.4). The same elasticities are applied to the EU, for want of a European counterpart to the LBNL cost series.

At measured shares of global additions—solar 0.095 (US) and 0.152 (EU), wind 0.119 and 0.160—the local curves reproduce 27.9 log points in the United States and 34.6 in the EU, or 42 and 52% of the global descent. The remaining 39 and 32 log points are the counterfactual descent that would not be reproduced if installed capital were priced only by the domestic experience stock.

Domestic content is a property of the technology. The manufacturing bound requires $\alpha_{d,j}$, the share of demand already met by domestic producers. Measured by technology and region, it varies by a factor of four across technologies and barely at all across regions (Table B.1). Wind turbines are large and costly to ship, so their manufacture localises; modules are dense, cheap to ship and dominated by Chinese scale, so it does not. The relevant dimension of α is therefore the technology, not the country. Note that the value I used are upper-bound manufacturing-capacity proxies relative to 2030 deployment needs and not current values.

Table B.1: Domestic content of renewable-equipment demand, $\alpha_{d,j}$.

Region	Technology	α	Basis
US	solar	0.17	module shipments, imports over total, 2022–2024
US	wind	0.72	equipment imports over additions at turbine prices, 2012–2023
EU	solar	0.15	module manufacturing capacity over 2030 deployment needs
EU	wind	0.80	turbine-component capacity over 2030 deployment needs

Sources: US solar, U.S. Energy Information Administration (2025), Table 6, "Source and disposition of photovoltaic module shipments" (0.06 in 2022, 0.21 in 2023, 0.23 over the first nine months of 2024). US wind, Wiser et al. (2024), data file, sheet "Wind Equip Imports over Time" (Berkeley Lab analysis of Census USA Trade Online) over annual additions valued at the OEM turbine transaction prices of sheet "Wind Turbine Prices"; the 2012–2023 range is 0.57 to 0.82 with no trend. EU solar, Chatzipanagi et al. (2025), Table 9, p. 59: EU module manufacturing capacity of 12 $\mathrm{GW_{DC}}$ against 76 $\mathrm{GW_{DC}}$ of 2030 deployment needs; upstream the EU is at 3% of needs for cells and zero for wafers and ingots. EU wind, Tapoglou et al. (2025), Table 6, p. 51: nacelle assembly 36.3/44.7 GW, blades 27.9/44.7, towers 41.7/44.7, weighted by turbine value; deployment needs follow REPowerEU, 510 GW by 2030 against 241.7 GW installed at end-2024 spread uniformly over the remaining years. The components covered are set out in Table 5, p. 50, and exclude the drivetrain, for which no data are available. *All four are upper bounds:* US module assembly from imported cells counts as domestic; the EU figures are manufacturing capacity rather than production, and the source notes that deployment will be exponential rather than linear, which understates the denominator.

Electricity-sector residual. Let $\gamma_K = \Delta \ln P^{\text{broad}} + D$, where the broad electric-plant deflator rises by 52.8 log points over the period. Under import sourcing, $\gamma_K^{\text{off}} = 52.8 + 66.5 = 119.3$ log points. The corresponding electricity-sector value-added residual is

$$B_K^{\text{off}} = s_K \omega_R \gamma_K^{\text{off}} \simeq 4.3\text{–}6.7$$

log points spanning the two capital-input constructions of Table 1.

It is useful to collect the combined exposure term as $\kappa \equiv s_K \omega_R$. The measured range implies

$$\kappa \in [4.334/119.3,\ 6.73/119.3] = [0.0363,\ 0.0564].$$

Under full US reshoring, the deflator gap falls to $\gamma_{K,\text{US}}^{\text{re}} = 52.8 + 27.9 = 80.7$ log points, so that

$$B_{K,\text{US}}^{\text{re}} = \kappa(80.7) \simeq 2.9\text{–}4.8$$

log points. Relative to import sourcing, the residual therefore falls by

$$\begin{aligned} B_K^{\text{off}} - B_{K,\text{US}}^{\text{re}} &= \kappa(66.5 - 27.9) \\ &= \kappa(38.6) \\ &\simeq 1.4\text{–}2.3 \end{aligned}$$

value-added log points.

Under full EU reshoring, $\gamma_{K,\text{EU}}^{\text{re}} = 52.8 + 34.6 = 87.4$ log points, which gives

$$B_{K,\text{EU}}^{\text{re}} = \kappa(87.4) \simeq 3.1\text{–}5.2$$

log points. The corresponding compression is

$$B_K^{\text{off}} - B_{K,\text{EU}}^{\text{re}} = \kappa(66.5 - 34.6) = \kappa(31.9) \simeq 1.2\text{–}1.9$$

value-added log points.

These calculations are the numerical counterpart of

$$B_K^{\text{off}} - B_K^{\text{re}} = s_K \omega_R \sum_j w_j \, b_j \ln\left(\frac{m_j}{1 + (m_j - 1)s_{d,j}}\right),$$

the experience ratio between the global and the domestic curve, technology by technology.

Comparison on a common value-added scale. Applying Equation (S.30) to the manufacturing side, let $\alpha_{d,j}$ be the share of demand already met by domestic producers, so that domestic manufacturers accumulate only that fraction of post-2011 domestic demand under current sourcing and all of it under full reshoring:

$$\Delta A_{M,d}^{\text{re}} = \sum_j w_j \, b_j \ln\left(\frac{1 + (m_j - 1)s_{d,j}}{1 + (m_j - 1)\alpha_{d,j} s_{d,j}}\right). \tag{S.31}$$

If the entire resulting unit-cost improvement is attributed to domestic manufacturing TFP—that is, if a fraction $\rho_d = 1$ of the observed learning-curve improvement is domestic manufacturing productivity—this gives at most 18.1 log points in the United States and 21.9 in the EU. Since B_K is expressed in electricity-sector value-added TFP units, the gain on the same scale is

$$\widetilde{\Delta A}_{M,d}^{\text{re}} = \nu_d \, \Delta A_{M,d}^{\text{re}}, \qquad \nu_d \equiv \frac{VA_{M,d}}{VA_{E,d}},$$

the ratio of renewable-manufacturing to electricity-sector value added.

This weight is measured. US solar-module and wind-equipment demand, valued at shipment and turbine transaction prices, was \$17.4 bn in 2023; at the BEA all-manufacturing value-added share of gross output (0.394) that is \$6.9 bn of value added, against \$368.9 bn for NAICS 2211, giving $\nu = 0.0186$.[5] The relevant weight is the reshored one, because the gain being converted is realised when domestic producers supply the whole domestic market; at current sourcing the domestic industry is worth $\nu = 0.007$. The measurement is a lower bound, excluding inverters, trackers, mounting and other balance-of-system manufacturing, the upstream cell, wafer and polysilicon stages, and offshore wind. The maintained $\nu_d = 0.02$ is therefore accurate to within a few percent and is retained as the round value, giving

$$\widetilde{\Delta A}_{M,\text{US}}^{\text{re}} = 0.02\,(18.1) = 0.36$$

electricity-sector-equivalent log points and

$$\widetilde{\Delta A}_{M,\text{EU}}^{\text{re}} = 0.02\,(21.9) = 0.44.$$

The corresponding compression of the broad-deflator electricity residual is $\kappa(66.5 - D_d^{\text{re}})$: 1.4 to 2.3 log points for the United States and 1.2 to 1.9 for the EU, as summarised in Table B.2.

The compression exceeds the manufacturing bound by a factor of three to six, and the comparison is constructed to favour the manufacturing side at every step. The bound sets $\rho_d = 1$, attributing all learning-curve improvement to domestic manufacturing TFP with no role for international knowledge spillovers, imported machinery and inputs, input prices, scale economies not captured as TFP, product composition or margins. The four domestic-content shares are upper bounds, and a higher α leaves less experience to be gained from reshoring. The compression, by contrast, is bracketed by the measured exposure range. Reshoring relocates some learning into domestic manufacturing, but not enough to offset the reduction in measured electricity TFP that follows from replacing the global price curve with a shallower domestic one.

[5] Equipment demand from U.S. Energy Information Administration (2025), Table 3, and Wiser et al. (2024); value-added share from BEA GDP-by-Industry, sector 31G; NAICS 2211 value added from BEA Underlying GDP-by-Industry. The 2022 figure is 0.0191.

Table B.2: Reshoring: manufacturing gain versus electricity-residual compression

	Manufacturing gain	Electricity-residual compression
United States	0.36	1.4–2.3
EU	0.44	1.2–1.9

Notes: Entries are in electricity-sector-equivalent value-added log points, evaluated at $\nu_d = 0.02$ and $\kappa \in [0.0360, 0.0595]$.

Single-curve alternatives. Collapsing the two technologies into one curve requires a single elasticity and a single experience stock, and the conclusion does not depend on how that is done. Taking the solar-PV experience exponent of Way et al. (2022, Table S24), $b = 0.319$, the observed descent implies three doublings of experience, $8 = 2^3$, since $3b \ln 2 = 0.663$; the local curves then reproduce 17.3 log points in the United States and 23.4 in the EU. Measured global wind and solar capacity in fact grows from 222 to 3,013 gigawatts, a multiple of 13.6; holding the observed descent fixed and letting that multiple pin down the elasticity gives $b = 0.255$, and local descents of 21.2 and 27.5. The two-technology construction gives 27.9 and 34.6. All three leave the local curves reproducing a minority of the global descent, and the manufacturing bound well below the electricity-residual compression.

C Output aggregation: by delivery time, not by generation source

The output-side analysis rests on two aggregation disciplines that pull in opposite directions and are both required. Electricity output should be differentiated by the hour and location of its delivery, because that is the margin on which its market value differs; and it should not be differentiated by the technology that produced it, because within a delivery cell a MWh is a homogeneous product. This appendix states both disciplines. Section C.1 defines the reference price behind the capture ratios of Section 2. Section C.2 makes the conceptual case that a shift of generation toward low-value hours is a fall in real output, not a price effect. Section C.3 shows that the opposite convention—splitting output by generation source and deflating each stream by its own production cost—creates artificial real-output growth.

C.1 The reference price and the value-weighted benchmark

Let

$$\bar{p}_t = \sum_h \tau_h \, p_{h,t}, \qquad \tau_{(m,n)} = \frac{\lambda_n}{M_t}, \qquad \sum_h \tau_h = 1,$$

be the reference price, the load-weighted average of each zone's baseload price, where λ_n is location n's share of load. One can check that $\sum_h \tau_h = \sum_n \sum_m \lambda_n / M_t = \sum_n \lambda_n = 1$: hours enter uniformly, locations by economic size. Because $v_t \equiv v_{r,t}/v_{d,t}$ is a ratio of capture ratios sharing $\bar{p}_t$ as a denominator, the reference price cancels: the weights λ_n affect neither Q_t^{val} nor $B_{V,t}$, and fix only the units in which capture ratios are quoted. For a single zone this is the arithmetic mean of hourly prices.

Q^{phys} and Q^{val} are conceptual benchmarks, not published series. Official real output, generically Q_t^{off}, is constructed in one of three ways: as a direct quantity index over strata such as customer classes, as current-dollar output deflated by a price index, or as a quantity extrapolation of a benchmark level. None of the documented constructions carries the hour or location of delivery as a stratum of the aggregation, so each behaves like Q^{phys} on exactly the margin along which renewable generation differs, while correctly refusing to split output by source. Section 4.1 states the premise; Supplemental Appendix D.1 documents the constructions and derives the condition under which the underlying output-value wedge survives as bias in a deflated-value series.

C.2 Why a shift toward low-value hours is a fall in real output

Proposition 2 records lower real output when the same annual MWh are delivered in lower-value hours. The natural objection is that a MWh is a MWh: if physical generation is unchanged, how can real output fall? The answer is that a volume index measures the basket, not the tonnage. Electricity delivered in different hours is not the same good, so a basket that shifts toward hours buyers value less is a smaller basket even at constant MWh. Three features of existing accounting practice already embody this principle, in ascending order of proximity to the electricity case.

First, seasonal goods. Strawberries in December and strawberries in July are different products in the accounts; a grower who keeps tonnage constant but shifts sales from December to July has produced less valuable output, and the volume index says so. The Eurostat handbook places summer versus winter gas in the same sentence as day versus night electricity and cross-references its own treatment of seasonal products (Eurostat, 2016, §4.4). Electricity, the least storable good in the accounts, is the strongest case for time-differentiation, not an awkward exception to it.

Second, the accounts already differentiate electricity by reliability, through tariffs. Interruptible industrial supply is priced below firm supply and treated as a different product, because the buyer has surrendered the right to consume at a moment of its choosing. That is time-and-system-state differentiation already inside the accounts; moving from "firm versus interruptible" to "hour by hour" is a change of resolution, not of principle.

Third, curtailment is the corner case everyone concedes. No one would count curtailed energy as output: energy the system cannot absorb has no value. A midday MWh clearing at two euros, or at a negative price, is one step short of curtailment—at a negative price the system is paying to absorb it. Accepting that curtailed MWh are not output means accepting that MWh are not fungible across hours; the only remaining question is where to draw the line, and the price draws it continuously, which is what an index is for. The limiting case makes the same point: if all MWh within a year were one product, a system that compressed its entire annual generation into a handful of hours, most of it unabsorbable, would record unchanged real output. Annual equal-weighting must break down somewhere; the argument is only about resolution.

The accounting standard reaches the same conclusion by its own test. ESA 2010 defines price discrimination as different prices for identical products sold "under exactly the same circumstances" (ESA 2010, §10.16). Two MWh delivered in different hours are not sold under the same circumstances—the system state differs—so by the standard's own criterion they are different products, and the price difference is quality, not discrimination. This is the provision documented in Appendix D.8.

Two objections deserve a direct answer. The first is that a kilowatt-hour boils the same kettle whenever it is delivered. It does not, because the consumer chose when to boil it, and the value of boiling it now rather than in eight hours is precisely what the hour-differentiated price measures; a consumer genuinely indifferent to timing already buys interruptible supply at a lower tariff—and receives a different product in the accounts. The second is that it seems perverse for real output to fall when the sun shines more. It falls only relative to a physical count; total value-weighted production still rises with deployment. Cheap midday power is a real gain—it is simply not electricity-sector output. It appears as lower input costs downstream and higher real household income, which is where a consumer-surplus gain belongs. As the discussion of Proposition 2 notes, B_V is a market-value benchmark, not a welfare measure.

C.3 The homogeneous-output discipline: why output is not split by source

Within a node and settlement interval, electricity is homogeneous across generation technologies. To isolate this point, this section sets the output-value gap to zero: all MWh delivered in the same market cell receive the same transaction price p, regardless of whether they were generated by wind, solar, nuclear, or fossil fuel. Differences in value across hours and locations are therefore suppressed here and treated separately in Section 4.

The distinction between technologies remains relevant on the input side. Renewable and conventional generating structures are physically different capital goods with separately observed replacement costs. It does not follow that their electricity injections are separate output products. Once delivered in the same market cell, a MWh is a MWh. Splitting output by generation source and assigning each stream its own production-cost index would therefore treat a production process as product variety.

Let the sector produce q_d conventional and q_c clean MWh, with

$$Q = q_d + q_c, \qquad \theta = \frac{q_c}{Q}.$$

Because both streams receive the common output price p, nominal electricity sales are

$$S = p(q_d + q_c) = pQ,$$

and deflating nominal sales by this common transaction price returns physical output:

$$Q^{\text{true}} = \frac{S}{p} = Q.$$

Consider instead an analyst who assigns the two technologies separate imputed prices c_d and c_c, such as source-specific levelized costs, and constructs the cost-valued aggregate

$$\widetilde{S} = c_d q_d + c_c q_c = \bar{c}Q, \qquad \bar{c} = (1-\theta)c_d + \theta c_c.$$

These imputed prices are production costs, not transaction prices for distinct output products.

Proposition 3 (Composition artifact from source splitting)**.** *Suppose the analyst treats clean and conventional electricity as separate products and deflates $\widetilde{S}$ with a separated-goods price index satisfying*

$$d\log P^{\text{sep}} = \omega_d \, d\log c_d + \omega_c \, d\log c_c, \qquad \omega_i = \frac{c_i q_i}{\widetilde{S}}.$$

To first order, the resulting real-output index differs from physical output by

$$d\log Q^{\text{sep}} - d\log Q = d\log \bar{c} - d\log P^{\text{sep}} = \frac{c_c - c_d}{\bar{c}} \, d\theta. \tag{S.32}$$

A shift toward the technology with the higher imputed cost therefore appears as additional real output even when total physical generation is unchanged.

Proof. Because

$$\widetilde{S} = \bar{c}Q,$$

we have

$$d\log \widetilde{S} = d\log Q + d\log \bar{c}.$$

The separated-goods quantity index satisfies

$$d\log Q^{\text{sep}} = d\log \widetilde{S} - d\log P^{\text{sep}}.$$

It follows that

$$d\log Q^{\text{sep}} - d\log Q = d\log \bar{c} - d\log P^{\text{sep}}.$$

Differentiating

$$\bar{c} = (1-\theta)c_d + \theta c_c$$

gives

$$d\log \bar{c} = \omega_d\, d\log c_d + \omega_c\, d\log c_c + \frac{c_c - c_d}{\bar{c}}\, d\theta.$$

Subtracting the separated-goods price index yields Equation (S.32). □

The result is a pure composition effect. If the imputed costs are fixed, a standard separated-goods price index records no inflation. A shift toward the higher-cost source nevertheless raises the analyst's cost-valued nominal aggregate, so the entire increase is recorded as real output.

Worked illustration. Hold total physical output fixed and let the clean share rise from 0.40 to 0.85. Suppose the imputed costs remain constant at

$$c_d = 50, \qquad c_c = 60.$$

The cost-valued unit value rises from

$$\bar{c}_0 = 0.60(50) + 0.40(60) = 54$$

to

$$\bar{c}_1 = 0.15(50) + 0.85(60) = 58.5.$$

Because the two source-specific cost indexes have not changed,

$$\frac{P_1^{\text{sep}}}{P_0^{\text{sep}}} = 1.$$

The separated account therefore reports

$$\log\left(\frac{58.5}{54}\right) \simeq 0.080,$$

or approximately 8 log points of real-output growth, despite unchanged physical generation. Deflation by the unit value of the cost-valued aggregate would remove this composition term and return zero quantity growth.

Remark 1 (The LCOE trap). A second artifact arises when actual electricity revenues are divided by source-specific production-cost indexes. Let

$$S_i = pq_i$$

denote the actual revenue associated with source i. Because the common output price is p, revenue shares equal generation shares. An analyst who deflates each revenue stream by its source-specific cost index obtains

$$d\log Q^{\text{LCOE}} = \sum_{i\in\{c,d\}} \theta_i \left(d\log S_i - d\log c_i\right).$$

Using

$$d \log S_i = d \log p + d \log q_i,$$

the difference from physical-output growth is

$$d \log Q^{\mathrm{LCOE}} - d \log Q = \sum_{i \in \{c,d\}} \theta_i \left(d \log p - d \log c_i \right). \tag{S.33}$$

Suppose the conventional cost index moves with the common output price, while the clean cost index falls relative to it at rate

$$\gamma_c = d \log p - d \log c_c > 0.$$

Equation (S.33) then reduces to

$$d \log Q^{\mathrm{LCOE}} - d \log Q = \theta \gamma_c. \tag{S.34}$$

This term exists even at a fixed generation mix. Falling clean production costs are recorded as greater real electricity output, although neither the physical quantity nor the market value of electricity has increased.

The relative cost decline γ_c is not published, but it is bounded by the gap between output-price growth and the observed decline in clean generation cost. Over 2010–2024 the NAICS 2211 output deflator rises 2.2% per year, while clean cost falls by between 4.8% per year on the BEA renewable capacity-cost index and 18.0% per year on IRENA solar LCOE; the implied γ_c therefore spans 7 to 20% per year, with the onshore-wind LCOE estimator at 11.6.[6] Taking a clean generation share of $\theta \simeq 0.17$ and the mid estimator $\gamma_c \simeq 12\%$ per year,

$$\theta \gamma_c \simeq 0.17 \times 0.12 = 0.0204.$$

Source-cost deflation would therefore add approximately 2 percentage points per year to measured sectoral output growth, and between 1.2 and 3.5 points across the range of γ_c above. At a clean share of one third, the same convention would add approximately 4 percentage points per year. Over a longer period, the cumulative artifact is

$$\sum_t \theta_t \gamma_{c,t}.$$

Because the clean share rises over the transition, the current annual rate should not be extrapolated backward over the full sample.

The two artifacts are distinct: Equation (S.32) is a composition effect created when an invented relative price is combined with a changing generation mix, whereas Equation (S.34) is a learning effect created when a falling input cost is used as an output deflator; both are separate from B_V, which reflects genuine differences in the market value of electricity delivered across hours and locations.

The official output series studied in Appendix D avoid both phantom-output terms because they neither split electricity by generation source nor deflate renewable output by LCOE; their limitation instead is that aggregation removes the time and location variation required to identify B_V.

[6] Estimators and sources in `Results/provenance_gap_closure.md`. The arithmetic below is linear in γ_c, so the span carries through proportionally.

D Where the output-value bias lives in official statistics

Proposition 2 compares two aggregation rules for delivered electricity: one that weights every MWh within the year equally, and one that weights MWh by the price prevailing in the hour and location of delivery. The proposition is a statement about aggregation and holds by construction. What requires documentation is the premise connecting it to published statistics: that official real electricity output behaves like the first rule rather than the second on exactly the margin along which renewable generation differs. This appendix establishes that premise from current agency methodology.

Section D.1 classifies the documented official constructions into three families and previews the form the premise takes in each. Section D.2 derives the accounting condition required in the deflated-value family, where the premise cannot be read off the deflator alone. Sections D.3–D.5 document the US constructions; Section D.6 examines what the available price indexes can and cannot register; Section D.7 isolates the one quantity that remains unidentified, the settlement pass-through. Sections D.8 and D.9 document the European framework and the two direct-quantity systems that implement its alternative branch. Section D.10 states what would overturn the premise, and Section D.11 summarizes. The empirical counterpart—the demonstration that the gap emerges from the same hourly data once hour and system state are introduced as strata—is in Appendix E.6.

D.1 Three families of official construction

Documented official measures of real electricity output fall into three families. In the first, *direct quantity aggregation*, the agency aggregates physical quantities across strata with value weights; nominal output and the deflator play no role in the volume index, whose properties follow entirely from the strata and weights. In the second, *deflated value*, real output is current-dollar output divided by a price index, and the volume properties depend jointly on what reaches the nominal numerator and what the price index absorbs. In the third, *quantity extrapolation*, a benchmark nominal level is carried forward by a physical quantity indicator and a price index, and real output tracks the quantity indicator by construction. The harmonised European framework treats the first two as equivalent A-methods for electricity, requiring for the direct branch quantities *sufficiently detailed by tariff and customer type* (Eurostat, 2016, CPA 35).

No stratum in any row of Table D.1 is defined by the hour or location of delivery. In the direct-quantity and extrapolation families that observation settles the premise outright: within each stratum-year every MWh carries the same weight, so the index inherits the equal-value-per-MWh property of Q^{phys} on the time-of-delivery margin, with no further condition. In the deflated-value family the same observation is necessary but not sufficient, for the reason the next subsection makes precise.

D.2 The deflated-value family: the premise is an accounting condition, not a property of the deflator

Write the capture factor of Section 2 as

$$C_t \equiv 1 - \theta_t(1 - v_t), \qquad Q_t^{\text{val}} = Q_t^{\text{phys}} C_t, \tag{S.35}$$

so that $B_{V,t}^{\text{gen}} = -\Delta \log C_t$. Under deflated value, official real output is a ratio,

$$Q_t^{\text{off}} \equiv \frac{V_t}{P_t}, \tag{S.36}$$

Table D.1: Documented constructions of official real electricity output.

System	Family	Strata of the volume aggregation
BLS industry productivity (documented utility method)	direct quantity (Törnqvist)	kWh sold to ultimate customers, by class of service (Bureau of Labor Statistics, nd)
BLS industry productivity (general method)	deflated value	revenues deflated at product-class level; product classes are customer classes and the utility/non-utility split (Bureau of Labor Statistics, 2017)
BEA industry accounts	deflated value	commodity cells deflated with electric-power PPIs, Fisher-aggregated (Bureau of Economic Analysis, ndb)
BEA personal consumption (household electricity)	quantity extrapolation	EIA residential kWh carried by the BLS electricity CPI (Bureau of Economic Analysis, 2025)
Eurostat / ESA 2010 (harmonised)	either A-method	PPI deflation, or quantities by tariff and customer type (ESA 2010, §10.32) (Eurostat, 2016)
UK ONS Index of Production, Section D	direct volume	energy-supply volume data supplied by DESNZ (Office for National Statistics, 2024)
Norway SSB national accounts	quantity extrapolation	monthly physical generation, inflated by recipient-group price indexes (Bougroug, 2021; Statistics Norway, 2026a)

of current-dollar output to a price index. Suppressing price components orthogonal to the value factor, let $\bar{p}_t$ denote the reference price of Section 2 and index the incidence of the capture factor on each side of Equation (S.36) by two exponents,

$$V_t = \bar{p}_t \, Q_t^{\text{phys}} \, C_t^{\varphi}, \qquad P_t = \bar{p}_t \, C_t^{\psi}, \tag{S.37}$$

where $\varphi \in [0, 1]$ is the *settlement pass-through*: the share of the capture-value change reaching recorded current-dollar output; and $\psi \in [0, 1]$ is the share the price index absorbs. Then $Q_t^{\text{off}} = Q_t^{\text{phys}} C_t^{\varphi-\psi}$ and the bias remaining in the published series is

$$\widehat{Q}_t^{\text{off}} - \widehat{Q}_t^{\text{val}} = (1 + \psi - \varphi) \, B_{V,t}^{\text{gen}}. \tag{S.38}$$

Table D.2: Incidence of the capture factor and the bias remaining in published real output, from Equation (S.38).

φ	ψ	Published real output behaves like	Residual bias
0	0	Q^{phys}	B_V^{gen}
1	0	Q^{val}	0
1	1	Q^{phys}	B_V^{gen}
0	1	below Q^{phys}	$2B_V^{\text{gen}}$

Two consequences discipline everything that follows. First, within this family the premise requires $\varphi \simeq \psi$, not $\psi \simeq 0$. Establishing that the deflator carries no capture-price signal is by itself uninformative, and taken in isolation points the wrong way: the second row of Table D.2 shows that if the capture-value loss reaches recorded revenue while the deflator ignores it, the loss remains in measured real output, which then tracks Q^{val} and leaves no bias at all. An argument resting only on the deflator therefore cannot support Proposition 2. Second, Equation (S.36) is not how every official series is built. Where the agency constructs real output directly from physical quantities, there is no ratio, φ and ψ do not arise, and the premise follows from the aggregation strata alone. That is why this appendix documents constructions before deflators.

D.3 US industry productivity: the documented method is a quantity index over customer classes

The BLS industry productivity program defines output on a sectoral basis: "Output is the total amount of goods and services produced in an industry for sale either to consumers or to businesses outside that industry." On construction, the program distinguishes two methods:

> "Real output is most often derived by deflating nominal sales or values of production using BLS price indexes, but for a few industries it is measured by physical quantities of output."
> "Where possible, physical quantity output indexes are Törnqvist aggregations of the quantities of individual products."[7]

Utilities are named among the physical-quantity sectors, and the program's electric-utility methodology specifies the quantity and the weights: output is "based on KWHs sold to ultimate consumers, not KWHs generated"; "KWHs sold to each class of service are weighted by the price of that service"; and class-of-service weighting "prevents bias in productivity measures due to changes in the distribution of sales among service classes" (Bureau of Labor Statistics, nd). This is the premise of Proposition 2 in the agency's own terms: real output is a Törnqvist index of kilowatt-hours sold, and the weights are class-of-service prices. The aggregation resolves the customer to whom a MWh is delivered, not the hour or location at which it is delivered. Every MWh sold to a given class within a given year enters with the same weight, irrespective of when it was produced — the equal-value-per-MWh property, holding on exactly the margin along which wind and solar differ from dispatchable generation, while correctly refusing to distinguish output by generating technology (Supplemental Appendix C.3). Under this construction the incidence problem of Section D.2 does not arise: recorded revenue is not an input to the quantity index, and the published output price index is implicit, recovered as current-dollar output divided by real output.

Uncertainty (i): industry and vintage coverage. Two gaps should be stated plainly. The handbook names "some industries within the . . . utilities . . . sectors" without enumerating them at the six-digit level, and the electric-utility methodology note is written on the SIC basis (SIC 491–493) that preceded the NAICS conversion, with source data from the Energy Information Administration. I have not located a current document stating that NAICS 2211 specifically is among the physical-quantity industries today. The alternative is that 2211 output is now built by the deflated-value method, which Section D.4 treats on its own terms. The premise survives under that method as well, for a different and weaker reason, and the two cases are kept separate throughout.

[7] Bureau of Labor Statistics (2017, Calculation). The physical-quantity method is used for "some industries within the mining, utilities, and transportation sectors, and at community hospitals, commercial banking, and postal services."

Uncertainty (ii): no official 2211 multifactor series. BLS publishes labor productivity and real sectoral output at NAICS 2211, but its published multifactor productivity measure for utilities is at NAICS 22, which includes natural gas distribution and water and sewage. The official series used as a comparator in this paper (`MPU0022`) is therefore broader in scope than the electricity sector and is labelled as a proxy; the electricity-only multifactor series is constructed and validated against `MPU0022` on a concept-matched gross-output basis. The BEA–BLS integrated production account likewise reports an aggregated Utilities industry rather than 2211 (Bureau of Economic Analysis and Bureau of Labor Statistics, 2026). No claim in this paper requires an official 2211 multifactor series to exist.

D.4 The deflated-value alternative, and why the premise weakens but survives

Where the deflated-value method is used, BLS describes it as follows: "Deflated value output indexes are derived from data on the value of industry output adjusted for price change"; "Revenues are deflated at the detailed product-class level to take into account changes in the mix of products over time"; and "The resulting real output indexes are conceptually equivalent to indexes that are developed using data derived from physical quantities of output" (Bureau of Labor Statistics, 2017, Calculation). The equivalence claim is informative about the cell structure: deflation is performed at the product-class level, and for electric power the product classes available in the price statistics are the customer classes of the distribution indexes and the utility/non-utility split of the generation index (Section D.6). No product class in that scheme is defined by hour or location of delivery.

Consequently, under the deflated-value method $\psi \simeq 0$ on the time-of-delivery margin: a shift of generation into low-price hours changes no product class's price, so the price index does not move on that account. From Equation (S.38) the residual bias is then

$$(1-\varphi)\, B^{\text{gen}}_{V,t}\,, \tag{S.39}$$

and the premise requires φ to be small rather than following automatically; Section D.7 treats φ. The premise is therefore robust to which construction BLS currently applies, in the sense that neither contains a time-of-delivery weight, but the two are not equally strong: under the physical-quantity method the bias is B^{gen}_V unconditionally, and under deflated value it is B^{gen}_V scaled by $(1-\varphi)$. Results in the main text are reported on the understanding that Equation (S.39) is the conservative case.

D.5 US national accounts: quantity extrapolation on the household component

The BEA industry accounts build industry real gross output by deflation: chain-type quantity indexes are prepared by deflating the current-dollar commodity composition of gross output with the corresponding commodity price indexes and combining the resulting commodity quantity indexes, with value added obtained by double deflation (Bureau of Economic Analysis, ndb). On the household side, however, the construction is a quantity extrapolation. The current methodology summary gives, for the electricity and natural gas component of personal consumption expenditures, the same source data at every vintage — benchmark years, non-benchmark years, the two most recent years, and the current quarterly estimates: "annual EIA data on kilowatt-hour and cubic-foot quantities used and BLS CPIs for electricity and natural gas" (Bureau of Economic Analysis, 2025, PCE, housing and utilities); the quarterly key-source documentation lists the same combination of EIA residential sales in MWh and the BLS electricity CPI. Current dollars are physical quantities carried by a price index, and real consumption is obtained by deflating with that same index, so real electricity consumption is identically the EIA physical quantity,

$$\text{real}_t = \frac{K_t \times C_t}{C_t} = K_t, \tag{S.40}$$

up to benchmark scaling and BEA's timing and coverage adjustments. Recorded revenue does not enter the construction, so on this component $\varphi = \psi = 0$ by construction and the equal-value-per-MWh property holds exactly. The same document reports that electric-utility components of government consumption and of private inventories are estimated from monthly EIA physical quantities combined with BLS PPIs, with real values obtained by direct valuation from quantities and prices.

Uncertainty (iii): a superseded handbook description. The December 2024 NIPA Handbook describes the same component differently, with annual current-dollar estimates built from EIA residential *revenue* and the most recent estimates from monthly EIA revenue, together with EIA kilowatt-hours and cents per kilowatt-hour adjusted from a billing to a usage basis and the BLS electricity CPI (Bureau of Economic Analysis, 2024a, Ch. 5). Under that description current dollars are observed revenue and Equation (S.40) does not follow. BEA states that the handbook reflects the 2024 annual update and was not revised for the 2025 update; the September 2025 summary is the current statement of source data and is the one relied on here. The discrepancy is recorded because it bears directly on whether $\varphi = 0$ on this component, and a reader consulting the handbook alone would reach the opposite conclusion.

Uncertainty (iv): scope. Personal consumption expenditures on electricity cover household purchases only, roughly a third of US electricity sales, and are a use of the electricity commodity rather than the industry output entering the productivity residual. Equation (S.40) is corroborating evidence on the household component, not a statement about real gross output of NAICS 2211.

D.6 What the price indexes can and cannot register

Whichever construction applies, the price statistics available for US electric power have no hour-of-delivery dimension. The PPI price concept is a specified transaction: "the net revenue accruing to a specified producing establishment from a specified kind of buyer for a specified product shipped, or service provided, under specified transaction terms on a specified day of the month" (Bureau of Labor Statistics, 2026b, Concepts), collected as realistic transaction prices including discounts, premiums, rebates and allowances, with quality adjustment when the specification changes. The industry cells are defined by seller type and customer class: the generation index prices the initial commercial transaction of generating establishments, split into utility and non-utility cells; the bulk transmission index prices transmission fees and charges; the distribution indexes are published separately for residential, commercial, and industrial power, subdivided by Census division (Bureau of Labor Statistics, 2005). Aggregation holds transaction specifications and their weights fixed between weight revisions, so a change in the composition of sales across cells does not move the index; only a change in the price of a sampled specification does.

Three implications follow. First, a shift of generation into low-price hours alters no sampled specification's price and changes no product class, so it cannot register as a price movement: $\psi \simeq 0$ on the time-of-delivery margin. Second, a relative price movement across hours is invisible for the same reason — there is no hourly stratum whose price could move. Third, the capture ratio $v_{j,t}$ of Section 4.2 is a generation-weighted object, and nothing in the PPI is generation-weighted at sub-monthly frequency. One clarification closes a natural objection: a PPI quote for a regulated utility is locally a ratio of dollars to kilowatt-hours — revenue for a specified customer class and rate schedule at a specified usage level. But the ratio is taken *within a held-constant specification*, priced on a single day of the month, and is never re-weighted across hours or across the sales mix. A quote that is locally a unit price is not thereby an aggregate unit value, and it is the re-weighting, not the ratio form, that would carry the capture signal.

The deflator is not an average revenue per MWh. It is worth establishing separately that the published output price index is not a unit value, since a unit-value deflator would force real output to equal physical output identically and make the premise trivially true. It does not. Over 2017–2024 the published NAICS 2211 output price deflator rose 25.5 percent, while current-dollar output divided by the Federal Reserve physical-production index — the implied average revenue per unit — rose 17.9 percent, a gap of 7.6 percentage points in seven years; the correlation of their annual log changes is 0.79, not unity.[8] A unit value in this sense is published, but by a different agency and not as a deflator: EIA's average retail price is reported revenue divided by reported kilowatt-hours sold (U.S. Energy Information Administration, 2026a).[9]

The generation cut. Over 2017–2024 the composite generation PPI rose 26.4% and the merchant cell — the one official series pricing non-utility wholesale generation — rose 47.0 percent, both peaking in 2022 with the gas shock, while wind and solar generation rose 127.9 percent, all non-hydro renewables 98.3 percent, and total generation 8.4 percent (Figure D.1).[10] The movements are dominated by fuel prices. The correct reading is narrow: no secular decline attributable to capture prices is *separately identified* in these series. It would be an overstatement to conclude that the capture component is zero, since a negative capture contribution could be masked by fuel, contract, and congestion movements of larger magnitude; the 47% rise in the merchant cell does not by itself bound the capture contribution. What the generation cut establishes is that B_V cannot be recovered by differencing published price series, which is the output-side counterpart of the reason B_K cannot be read off a vintage difference (Supplemental Appendix A.1).

D.7 The one quantity that is not identified: settlement pass-through

Under the deflated-value construction the residual bias Equation (S.39) depends on φ, the share of the capture-value change that reaches recorded current-dollar sectoral output. Three features of US market organisation bear on it, and all point in the same direction. Most electricity reaches final customers at tariffs set in regulatory proceedings and revised at intervals of years, so a fall in the wholesale price prevailing in windy or sunny hours does not reduce retail revenue in the period in which it occurs. In vertically integrated utilities the generating plant and the retail business are the same firm, and generation is transferred internally rather than sold at an hourly market price, so no hourly price enters the accounts. Merchant renewable capacity typically sells under

[8] Author's calculation from BLS series `IPUCN2211T010000000` and `IPUCN2211T050000000`, with the physical benchmark from Federal Reserve G.17 `IPG2211A`. Over 1987–2024 the deflator rises from 65.3 to 125.5 and the implied unit value from 57.0 to 117.9 on a 2017=100 scale.

[9] Three statistics should not be conflated: the CPI for electricity, which prices selected rate schedules at consumption amounts drawn from Department of Energy information (Bureau of Labor Statistics, 2026a); the BLS average price per kilowatt-hour, a dollar level computed from the CPI utility sample; and EIA's average revenue per kilowatt-hour, the only one of the three mechanically equal to revenue divided by quantity.

[10] Generation and technology splits: US generation by fuel in TWh, EIA data retrieved through Ember's yearly full release, which is exhaustive and additive across fuels and therefore allows the component contributions to be checked against the total. Generation PPIs: BLS `PCU221110221110` (composite), `PCU2211102211104` (utilities), `PCU2211102211105` (non-utilities); monthly, annualized, rebased 2017=100.

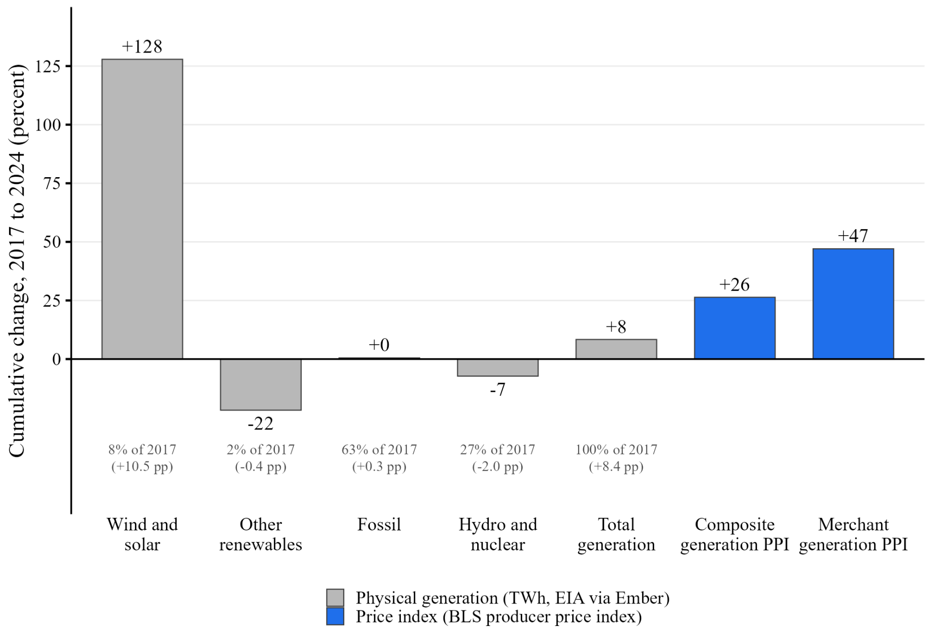

Figure D.1: Physical renewable generation roughly doubled while generation price indices rose (NAICS 22111, 2017–2024). Grey bars are physical generation in TWh (EIA, via Ember); the four component categories are mutually exclusive and exhaustive, so their contributions sum to the change in total generation, and the 2017 share and percentage-point contribution of each are printed below the axis. Blue bars are price indices (BLS producer price indices, monthly, annualized with February 2021 excluded, rebased 2017=100), which rose on fuel cycles peaking in 2022. The two are not commensurable: both are cumulative percent changes over the same window, but the juxtaposition is of direction, not of a common unit. The merchant cell prices wholesale rather than bundled retail output and is the natural home for a cannibalization signal. Neither PPI is the NAICS 2211 output deflator, and under a physical-quantity output construction neither deflates anything. Because the indices are monthly, matched-model and nationally aggregated, they resolve neither the intraday nor the regional structure on which $v(\theta)$ turns, and no capture-price decline is separately identified in them.

long-dated power purchase agreements or contracts for difference at a fixed strike, so the generator's receipts are insulated from its own capture price and the difference is borne by the offtaker. Under cost-of-service regulation the revenue requirement is costs plus allowed return, which a capture-price decline does not reduce; the shortfall is recovered in subsequent rate proceedings. Recorded sectoral output is thus not merely insensitive to the capture-value loss but may move against it.

I do not estimate φ. It is identified in principle from data already published: EIA Form 861 reports sales in MWh, associated revenue, and customer counts by state and customer class, distinguishing bundled, energy-only, and delivery-only service; EIA Form 923 and FERC Form 1 identify the utility and merchant split of generation and its contractual disposition (U.S. Energy Information Administration, 2026a). An estimate of φ would convert Equation (S.39) from a bound into a point measure and is the natural next step on the output side, in the same way that a region-level capture-weighted US output index built from hourly generation and nodal prices is the natural next step on the price side.

D.8 The European framework: one concept, two A-methods, national implementation

The European framework is examined at three levels: the accounting standard, the harmonised methodology, and the national instruments that implement it.

The standard endorses the concept. ESA 2010 classifies time-of-day variation — "electricity supplied at night compared with supply during the day" — as a quality margin to be recorded as a change in products rather than in price (ESA 2010, §10.16). An output account implementing that provision would carry each hour of delivery as a distinct product and would register the shift of generation toward low-value hours directly, exactly as Q^{val} does. The concept in this paper and the concept in the standard therefore coincide: the bias is a granularity gap in the instruments implementing the standard, not a conceptual error in the standard itself. The treatment is, however, permissive rather than required: the handbook's best-practice condition for a quantity-based volume measure is only that quantities be identified by tariff and customer type, in which hour of delivery does not appear.

The harmonised methodology permits two A-methods. For electricity (CPA 35), the Eurostat handbook on price and volume measures identifies as A-methods both the deflation of output values by a suitable producer price index and the use of quantity indicators *sufficiently detailed by tariff and customer type*, which it regards as equivalent (Eurostat, 2016, CPA 35); value added is in principle obtained by double deflation, with separate volume measurement of output and intermediate consumption (ESA 2010, §10.32). The two branches map directly onto the families of Section D.1: under the direct branch there is no numerator and no deflator, and the premise follows from the quantity cells; under the deflated branch it follows from the accounting condition of Section D.2. In neither branch does the harmonised requirement introduce an hour or location stratum: the prescribed detail is tariff and customer type.

The price instruments are harmonised in concept, national in construction. The legal definition of the industrial producer-price variable requires an actual transaction price at basic prices, specified by its price-determining characteristics and adjusted for quality change, compiled monthly for NACE Section D (European Parliament and Council of the European Union, 2019; European Commission, 2020); the mandatory harmonised breakdown is generally at the electricity-gas-steam division level rather than electricity generation specifically. Within that frame, the elementary price concept, sampling, and aggregation are set nationally and differ materially: Finland's metadata state that "the price data collected from enterprises are quantity weighted average prices," resorting to "the price of the delivery/billing/payment time on the 15th day of the month" only where an average cannot be determined (Statistics Finland, 2026); Spain's describe prices observed around the 15th of the month with geometric-mean elementary aggregation; Denmark's describe geometric means of matched observations within detailed commodity aggregates, following the 2012 PPI handbook (Eurostat, 2026b, 2012). None of the examined metadata documents an hour-by-bidding-zone stratification. Two conclusions follow, one firm and one deliberately bounded. Firmly: no published harmonised requirement or examined national metadata stratifies the electricity PPI by hour and location of delivery, so no European deflator is documented to price the capture margin as a product dimension. Bounded: the compilation manual asks not for a price on a nominated day but for a period average, and singles out volatile products of macroeconomic importance.[11] Because some national constructions admit quantity-weighted or unit-value-type elementary prices, part of the within-month settlement variation may enter some national indexes, so $\psi \simeq 0$ is a country-by-country hypothesis for Europe rather than a proven uniform property. This bound does not weaken the premise: by Table D.2, $\psi > 0$ with low pass-through φ *raises* the residual bias above B_V^{gen}.

Translation into value-added productivity. European and UK multifactor productivity is computed on real value added obtained by double deflation, not on gross electricity output (Eurostat, 2016; Office for National Statistics, 2025). Let Y be gross output, M intermediate consumption, and $GVA = Y - M$. If only the output volume is mismeasured,

$$d \log GVA^{\text{off}} - d \log GVA^{*} \simeq \frac{Y}{GVA}\left(d \log Y^{\text{off}} - d \log Y^{*}\right),$$

so a gross-output volume bias is amplified in value-added growth by the ratio Y/GVA, holding intermediate-input volumes fixed. Measured on the same NAICS 2211 accounts used in Table 1, that ratio runs from 1.38 to 1.78 over 2010–2024 with a mean of 1.58, so the amplification is roughly one and a half rather than the two-to-two-and-a-half typical of more fuel-intensive definitions of the industry.[12] Holding intermediate-input volumes fixed. Purchased electricity, fuel, and balancing services on the input side may partially offset this, and the net value-added bias is $B_{GVA} \simeq (Y/GVA)B_Y - (M/GVA)B_M$. The gross-output basis used in the main text is therefore the conservative one for comparison with value-added productivity statistics.

D.9 Two direct-quantity systems: the United Kingdom and Norway

The direct branch of the European methodology is not hypothetical. Two systems with unusually rich underlying energy data implement it, and both illustrate that data granularity does not translate into index granularity.

[11] Eurostat (2021, pp. 34–35): "The index should in principle reflect the average price during the reference period. In practice the information actually collected may refer to a particular day in the middle of the reference period ... For products with a significant impact on the national economy that are known to have, at least occasionally, a volatile price development, it is important that the index does indeed reflect average prices." Electricity satisfies both conditions. If a respondent computes that average as revenue divided by quantity over the month, the observation is a within-month unit value and absorbs the intraday component of the capture-price decline, which is the larger component since the margin is primarily diurnal. If it is the average price of a fixed specification, hour-composition is not a specification characteristic and does not enter. The manual does not resolve which practice applies to wholesale electricity, and respondent-level collection procedures are not public.

[12] Nominal gross output over nominal value added, BEA industry accounts for NAICS 2211; see `Results/provenance_gap_closure.md`.

United Kingdom. For the Index of Production, the ONS reports that Section D — electricity, gas, steam and air-conditioning supply — is measured from energy-supply volume data supplied by the Department for Energy Security and Net Zero, classified as direct-volume sources rather than Monthly Business Survey turnover deflated by a price index (Office for National Statistics, 2024). There is accordingly no current-value numerator and no deflator in the short-term electricity volume: the incidence parameters of Section D.2 do not arise, and the operative question is the stratification of the supplied volume data. The published methodology identifies energy-supply categories, not hour-location cells, so within each supplied stratum the index carries equal weight per unit of energy; the public documentation does not disclose the low-level aggregation cells, so the statement supported is that the construction does not mechanically incorporate capture prices, not that its residual bias is exactly B_V^{gen}. ONS multifactor productivity then uses quarterly-national-accounts value added as its output concept (Office for National Statistics, 2025), so the translation of the preceding subsection applies.

Norway. Statistics Norway extrapolates electricity-production volume from monthly electricity statistics — essentially physical generation — and inflates it with weighted price indexes for major recipient groups (households, ordinary industries, energy-intensive manufacturing), drawn from a quarterly survey of average prices and quantities by contract type and consumer group (Bougroug, 2021; Statistics Norway, 2026a). The construction is thus a quantity extrapolation on the output side: a wind MWh generated in a low-price, wind-abundant hour receives the same volume weight as a hydro MWh generated in a scarce evening hour. Norway is instructive because the raw data to do otherwise exist and are partially used: since October 2025 SSB values cross-border electricity flows at 15-minute Nord Pool prices in the external-trade statistics (Statistics Norway, 2026b). High-frequency *valuation* of the nominal numerator, however, is not high-frequency *volume aggregation*: if the same interval prices are used to deflate the interval-valued revenue, real output is again physical MWh, with the interval variation assigned entirely to the price component. Eliminating the bias requires carrying the interval-zone cells into the volume index as products — the treatment ESA 2010 §10.16 already endorses — and no documented Norwegian national-accounts series does so. On the capital side, SSB deflates electricity-industry investment by asset and product with separate domestic and import price components, which mitigates B_K without a renewable capacity-cost index; the Norwegian system therefore partially addresses the capital bias while leaving the output-value bias uncorrected, consistent with the timing asymmetry of Section 2.

D.10 What would overturn the premise

The premise fails under any of the following, and each is checkable.

1. *Hour-differentiated product classes.* If BLS or a European statistical institute were to stratify electricity output by time and location of delivery — whether as product classes for deflation or as products in a quantity aggregation — the resulting index would be value-weighted on the relevant margin and the bias would vanish by construction. This is the treatment ESA 2010 §10.16 already endorses in principle.

2. *A price cell settled on generation-weighted revenue.* If a PPI cell (in the US, the merchant generation quote; in Europe, a national elementary aggregate) were collected as revenue divided by output over a settlement period, with weights updated within the period, the cell would move with the capture price and ψ would rise toward one. The US published price concept — a specified transaction on a specified day — indicates otherwise, but the sampling detail for wholesale transactions is not public, and several European national metadata admit

quantity-weighted monthly averages; this is the single most consequential unverified fact in this appendix. Note that by Table D.2, $\psi > 0$ with low φ enlarges rather than removes the residual bias; only $\psi \simeq \varphi \simeq 1$ would eliminate it through the price side.

3. *High settlement pass-through under deflated-value construction.* If output is built by deflating revenues and φ is near one while $\psi \simeq 0$, then by Equation (S.39) the published series already registers the capture-value loss, so the underlying wedge does not generate bias in official statistics. This combination is the substantive form of the objection, and it is why Section D.7 treats φ as the open quantity rather than asserting it. It cannot arise in the direct-quantity and extrapolation constructions of Sections D.3, D.5, and D.9, where recorded revenue does not enter the volume index.

D.11 Summary

Five constructions of official real electricity output are documented above, and the premise of Proposition 2 holds under each, for different reasons and with different strength.

Table D.3: Constructions of official real electricity output and the status of the equal-value-per-MWh premise.

Construction	Aggregation strata	Residual bias
BLS physical-quantity index (kWh sold to ultimate customers)	class-of-service prices; no hour or location	B_V^{gen}, unconditional
BLS deflated value (product-class deflation)	product classes = customer classes; no hour or location	$(1-\varphi)B_V^{\text{gen}}$; φ bounded, not estimated
BEA PCE quantity extrapolation (EIA kWh carried by CPI)	none; real output $\equiv$ physical kWh	B_V^{gen}, exactly, on the household component
European deflated value (PPI A-method)	national elementary cells; no documented hour-location strata	$(1+\psi-\varphi)B_V^{\text{gen}}$; $\psi \simeq 0$ a national hypothesis
UK / Norway direct volume and extrapolation	energy categories, recipient groups; no hour or location	B_V^{gen} up to undisclosed low-level cells

In no documented case does the volume aggregation resolve the hour or location of delivery. That, and not any property of an output deflator taken in isolation, is what Proposition 2 requires. The capture-price decline is therefore not recoverable from published annual output aggregates and must be measured directly from hourly generation and prices, as in Section 4.2.

E Measuring the output-value bias in market data

This appendix documents the market-data measurement behind Section 4.2 and Figure 2. Section E.1 defines the price concept and the value factors and describes the European panel; Section E.2 describes the US market construction. Section E.3 reports value-factor schedules estimated from own-zone variation, as a diagnostic on the cross-border schedules adopted in the calibration. Section E.4 converts the level gap into annual growth-bias averages and adjusts for common price shocks. Section E.5 shows that the European level evidence is robust to the treatment of negative prices and curtailment. Sections E.6 and E.7 construct a narrower chained-volume benchmark under alternative delivery-time stratifications and examine its sensitivity to the 2021–2023 price shock.

E.1 Price concept, value factors, and the European panel

Price concept. The price entering the capture ratio is the zonal day-ahead price, not the generator's total remuneration. Feed-in tariffs, contracts for difference, power-purchase agreements, and other contractual transfers may insulate receipts from the hourly market price; using those receipts would therefore combine the value of delivered energy with the support or risk-sharing arrangement attached to the plant. The day-ahead price instead measures the market value of an additional MWh in a given hour and zone under the prevailing network constraints and market rules. Negative prices are retained. This is a market-value benchmark, not a measure of generator profitability or social welfare.

Value factor. Following Hirth (2013), I define *value factor* as the generation-weighted average price a technology earns, divided by the time-weighted average price of the zone. For technology j in zone z and year t, over the settlement hours h of that year,

$$v_{j,z,t} = \frac{\bar{p}^{\text{cap}}_{j,z,t}}{\bar{p}_{z,t}} = \frac{\sum_h p_{z,t,h}\, g_{j,z,t,h} / \sum_h g_{j,z,t,h}}{\sum_h p_{z,t,h} / H_{z,t}}, \tag{S.41}$$

where $p_{z,t,h}$ is the day-ahead price, $g_{j,z,t,h}$ the generation of technology j, and $H_{z,t}$ the number of settlement hours. The numerator $\bar{p}^{\text{cap}}_{j,z,t}$ is the technology's *capture price* and the denominator $\bar{p}_{z,t}$ the *baseload price*; $v_{j,z,t}$ is a unit-free ratio, so no deflation enters. A value factor of one means the technology earns the average price, and $v_{j,z,t} < 1$ is the cannibalization discount that arises when output is concentrated in low-price hours. I compute Equation (S.41) directly from ENTSO-E hourly day-ahead prices and generation for 15 European bidding zones over 2015–2024; own-technology penetration $\theta_{j,z,t}$ is generation over load on the same panel.

E.2 US market construction

The underlying observations are published by CAISO and ERCOT; the gridstatus.io hosted API is used as a programmatic access and harmonization layer. CAISO day-ahead prices are drawn from the ISO's Open Access Same-Time Information System (OASIS), while generation and load are based on CAISO's official production and system-demand series (California Independent System Operator, 2026a,b,c). ERCOT day-ahead prices are drawn from the DAM Settlement Point Prices product, generation from the Fuel Mix reports, and load from the system-load archives (Electric Reliability Council of Texas, 2026a,b,c). The series are retrieved through the gridstatus.io hosted API (Grid Status, 2026).

I apply the same hourly accounting construction as in the ENTSO-E panel. For each technology j, the capture price is the generation-weighted day-ahead price, the baseload price is the time-weighted day-ahead price, and penetration is generation divided by load. Negative prices are retained. Negative generation observations, where present, are set to zero before constructing the generation weights. The resulting sample covers CAISO from 2020 to 2025 and ERCOT from 2018 to 2025, corresponding to the years for which the required price, generation, and load series are jointly available.

Because CAISO does not publish a single day-ahead system price, I construct the reference price as a load-share-weighted average of the PG&E, SCE, and SDG&E default load-aggregation-point prices, using approximate weights of 0.45, 0.43, and 0.12. These weights are calculated from their average shares of system load over the sample. The resulting benchmark matches the system-wide aggregation of generation and load used in the calculation. Pricing all CAISO generation at a single node instead would change the result substantially, and in either direction: in 2024 the solar value factor is 0.40 against the SCE load-aggregation point and 0.74 against PG&E, a spread of 0.34, compared with 0.58 on the load-weighted average.[13] The dispersion is a solar phenomenon and it supports the system-wide benchmark rather than treating any one regional node as the price of all CAISO generation.

For ERCOT, I use the ERCOT-wide hub average `HB_HUBAVG`, reported among the market's hub settlement points (Electric Reliability Council of Texas, 2026a,d). Generation and load are system-wide balancing-area totals. For the categories shown in Figure 2, a market-year is classified as solar-dominated when solar accounts for at least 60% of wind-plus-solar generation,

$$\frac{\theta_s}{\theta_s + \theta_w} \geq 0.6,$$

wind-dominated when this share is below 0.4, and mixed otherwise. Marker shape identifies the market-data source: circles denote ENTSO-E bidding zones, triangles CAISO, and squares ERCOT.

In 2024, CAISO records an output-value gap of 11.7% at 38.4% wind-and-solar penetration (6.5% in whole-sector units); ERCOT records 5.3% (2.9% in sector units). The elevated ERCOT observation in 2021 reflects the February winter-storm price spike.

E.3 Within-variation in the value-factor schedules

This subsection asks whether own-zone variation produces the same qualitative relationship between penetration and value factors. It is not the source of the schedule used in the calibration. The domestic specification includes own-zone penetration but not neighbouring penetration, whereas cannibalization in interconnected markets may operate through generation elsewhere in the market. It therefore does not identify the full cross-border effect estimated by Stiewe et al. (2025).

For each technology $j \in \{s, w\}$ I estimate the value-factor schedule on the panel of European bidding-zone-years (ENTSO-E, 2015–2024; zone-years with own-technology penetration above 0.5 percent),

$$v_{j,z,t} = v_{0,j} - a_j\, \theta_{j,z,t} + \mu_z + \lambda_t + \varepsilon_{j,z,t}, \qquad j \in \{s, w\}, \tag{S.42}$$

estimated separately by technology, where $v_{j,z,t}$ is the generation-weighted capture price over the time-weighted baseload price, $\theta_{j,z,t}$ is own-technology generation over load, and μ_z, λ_t are bidding-zone and year fixed effects. The schedule slope $a_j = -\partial v_j / \partial \theta_j$ is the cannibalization rate, signed so that a positive a_j means the value factor falls as own penetration rises, matching the $v = v_0 - a\theta$ parameterization of Hirth (2013) and Stiewe et al. (2025). Standard errors are clustered by bidding zone (CR1). Table E.1 reports the estimates.

Figure E.1 displays the same estimates. Its two columns are the two technologies (solar, wind) and its two rows are two views of the identical data. The *top row* plots the raw value factor against own-technology penetration; the solid line is the pooled slope, which confounds the within-system relationship the mechanism concerns with fixed cross-system differences (a structurally sunny, high-solar-value zone need not resemble a windy one). The *bottom row* is the Frisch–Waugh–Lovell partialling-out plot: the value factor and penetration are each first regressed on the zone and year dummies, and the two sets of residuals are plotted against one another. This removes everything attributable to *which zone* an observation is and *which year* it falls in — fixed locational differences and common annual shocks such as gas-price cycles and weather years — leaving only the within-zone, within-year covariation that identifies a_j. By the Frisch–Waugh–Lovell theorem the slope

[13] Computed from the hourly day-ahead prices and hourly solar generation in `Data/us_hourly_cache`; see `Results/provenance_gap_closure.md`. The corresponding wind value factors are tightly clustered, 0.96 at every node, because wind output is not concentrated in the hours when nodal prices diverge.

Table E.1: Value-factor schedule slopes, European bidding-zone panel (ENTSO-E, 2015–2024). The slope $a_j = -\partial v_j/\partial\theta_j$ is the cannibalization rate (positive: value factor falls with own penetration). "Pooled" omits fixed effects; "Within" is the two-way (zone + year) fixed-effects estimator of Equation (S.42). Clustered standard errors (by bidding zone, CR1) in parentheses; with G clusters, t-statistics should be assessed against $G-1$ degrees of freedom. The Stiewe et al. (2025) row is the cross-border spatial estimate (domestic + neighbor) adopted in the calibration.

	Solar	Wind
Pooled slope a_j (no FE)	0.62	0.24
Within slope a_j (two-way FE)	0.62	0.35
(clustered SE)	(0.32)	(0.12)
t-statistic	1.96	2.90
Zone-years N	129	128
Bidding zones	15	14
Stiewe et al. (2025) spatial a_j	3.88	1.09

of this residual scatter is exactly the two-way fixed-effects coefficient of Equation (S.42), so the bottom row is a direct picture of the identifying variation rather than the confounded pooled cloud above it. The red dashed line in each panel is the Stiewe et al. (2025) cross-border slope, drawn on the same axes for comparison.

The within slopes are positive and far below the spatial estimates (solar 0.62 against 3.88; wind 0.35 against 1.09). The wind slope is significantly positive ($t = 2.90$ against a 5% critical value of 2.160 at $G-1 = 13$ degrees of freedom); the solar slope is marginal ($t = 1.96$ against 2.145 at $G-1 = 14$), as one would expect with fifteen clusters. This is the pattern the design predicts rather than a contradiction: differencing out zone and year effects removes the neighbor-penetration spillovers that the cross-border spatial design exploits, and cannibalization operates through the interconnected market price, not the domestic generation share alone. The domestic panel therefore recovers only the own-market component of the schedule, which is why the calibration adopts the spatial estimates. What the exhibit establishes is narrower and sufficient for the argument here: within the same European data the sign is right and, for wind, statistically distinguishable from zero, and the pooled and within slopes are of the same modest order—so the object placed inside productivity accounting is a schedule these data are consistent with, not one re-estimated from within-country variation.

E.4 Annual growth-bias averages and common price shocks

The generation growth bias, $B_V^{\text{gen}} = -\Delta\log(1-D)$, averages 0.53 percentage points per year across the European panel. I compute the bias from the observed year-to-year change in $D = \theta(1-v)$ for each zone and then average across zone-year observations. The average is concentrated after 2019, when common price shocks—COVID, the 2022 gas-price spike, and the subsequent normalisation—moved value factors in all zones simultaneously. Removing the common annual movement, by subtracting each year's cross-zone mean deviation from every zone's value factor, lowers the average to 0.12 percentage points per year, with the pre-2020 bias values close to zero. To express the bias as a contribution to whole-sector TFP growth, I weight it by generation's share of sector output, $B_{V,t} = w_G B_{V,t}^{\text{gen}}$ with $w_G \simeq 0.55$ the maintained generation share for NAICS 2211, which also includes transmission and distribution. This exercise is descriptive: it is not used to calibrate the forward value-factor schedules of Appendix F. Unlike the capital-side correction, which also

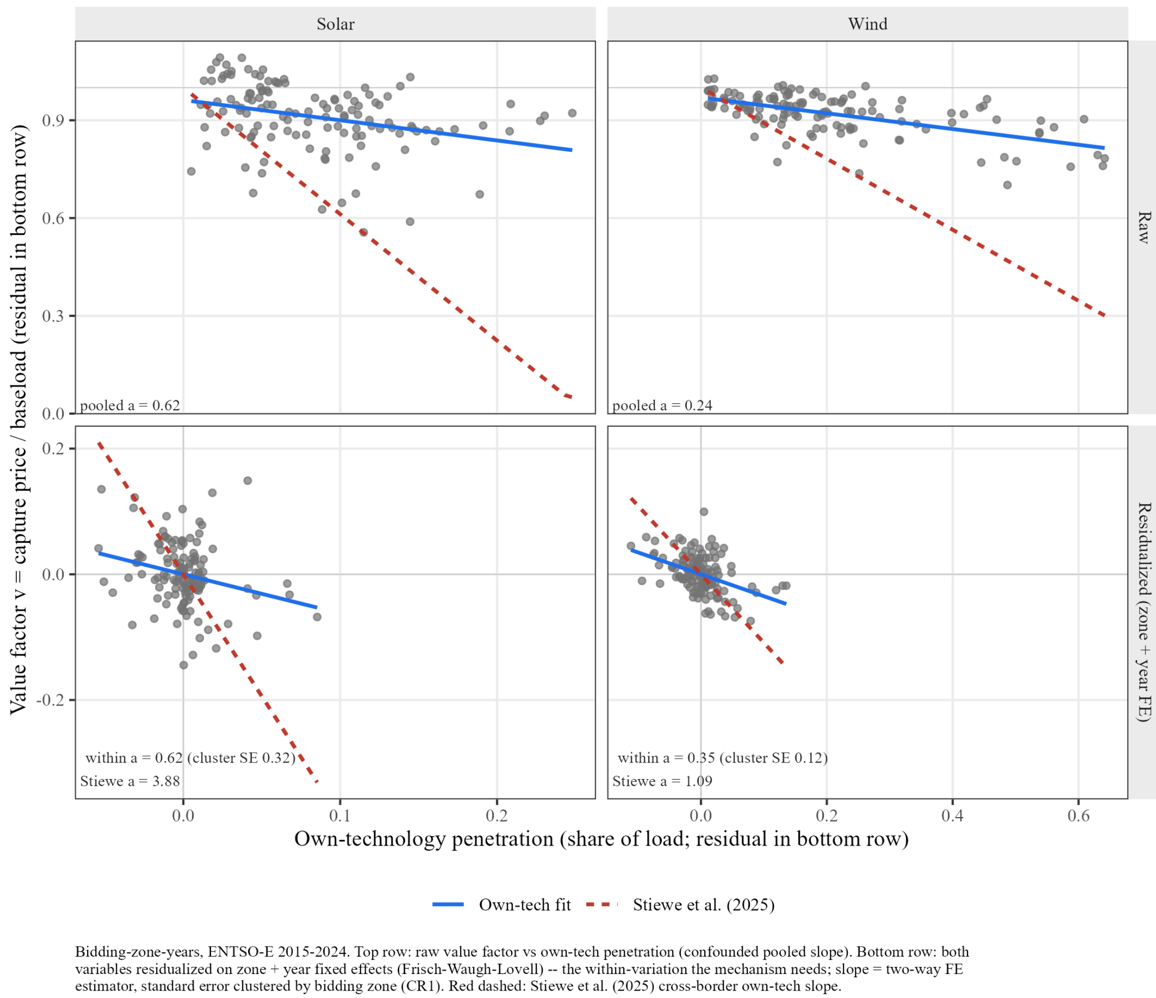

Figure E.1: Value factors against own-technology penetration, raw (top row) and residualized on zone and year fixed effects (bottom row), for solar (left) and wind (right). Solid line: own-technology fit (pooled slope in the top row, two-way within slope in the bottom); red dashed line: Stiewe et al. (2025) cross-border spatial slope. Standard errors clustered by bidding zone. Specification and point estimates in Equation (S.42) and Table E.1.

reinterprets past measured input growth, the calibrated output-side bias arises mainly as renewable penetration increases going forward.

E.5 Negative prices and curtailment

Two checks address the concern that the measured gap reflects market-design artifacts rather than value. Flooring day-ahead prices at zero, which deletes the contribution of negative-price hours, leaves the West Denmark 2024 generation-basis gap essentially unchanged (18.5 to 18.4 percent) and lowers the mean over the four-zone robustness subset (DK1, DK2, DE-LU, IE, 2019–2024) from 8.0 to 7.9 percent: the level gap is not a negative-price artifact, because negative hours in these zones are shallow relative to the mean price. Including curtailed energy, which the transparency-platform generation series excludes, works in the opposite direction from the concern: adding all-island Irish wind dispatch-down back into penetration raises the Irish gap by 0.3–0.5 percentage points (2020:

θ 0.449 to 0.501). German curtailment is not consistently measurable across the October 2021 Redispatch 2.0 reform and is left out; Danish curtailment is negligible.

E.6 A narrower chained-volume benchmark

One issue concerns Q^{val} rather than official practice. Equation (4) evaluates output at contemporaneous relative values, whereas a chained volume index excludes pure relative-price movements. The two channels of Equation (5) therefore have different index-number interpretations. For each technology j, I decompose in a price and quantity terms,

$$\Delta[\theta_j(1-v_j)] = (1-\bar{v}_j)\,\Delta\theta_j - \bar{\theta}_j\,\Delta v_j.$$

where bars denote arithmetic means across the two periods. Let $\mathcal{L}_t$ denote the logarithmic mean of $1-D_{t-1}$ and $1-D_t$. Then

$$B^{\text{gen}}_{V,t} = \frac{\sum_j \Big[(1-\bar{v}_{j,t})\Delta\theta_{j,t} - \bar{\theta}_{j,t}\Delta v_{j,t}\Big]}{\mathcal{L}_t},$$

with $\mathcal{L}$ the logarithmic mean,

$$\mathcal{L}_t \equiv \frac{(1-D_t)-(1-D_{t-1})}{\log(1-D_t)-\log(1-D_{t-1})}.$$

which gives an exact additive decomposition of the log bias. The first term is a quantity-composition effect; the second captures changes in relative value, including pure relative-price movements that a volume index records as prices rather than quantities. The composition channel accounts for 34% of the cumulative European bias and 41% of the US bias. Retaining that channel alone moves the central crossover from $\theta^\star = 0.40$ to 0.66; under the wind-heavy schedule, no crossover occurs within the modelled range.

Alternative delivery-time stratifications. Table E.2 constructs the narrower quantity-composition measure directly. Each specification applies the same chained Törnqvist formula to the same hourly prices and generation, varying only the aggregation strata. With month-by-hour cells, the cumulative gap is 6.2 log points in solar-dominated CAISO but slightly negative in wind-dominated ERCOT. With residual-load deciles, it is 6.9 log points in CAISO and 7.2 in ERCOT. Across Europe, the median rises from 0.25 log points under clock-time cells to 0.76 under residual-load deciles, with positive residual-load estimates in 13 of 15 zones.

The contrast is consistent with the technologies' temporal profiles. Solar output is strongly patterned by month and hour, so clock-time cells capture much of its reallocation across delivery periods. Wind varies substantially across days within the same clock-time cell. Residual-load strata distinguish those system states and can therefore reveal a quantity-composition margin that clock-time aggregation misses.

The levels are less robust than the ordering across stratifications. Dropping the 2021–2022 and 2022–2023 transitions, and then also 2020–2021, leaves the European residual-load median positive at 0.89 and 0.66 log points and positive in 12 and 10 of 15 zones. Clock-time estimates remain below residual-load estimates on the European median and in ERCOT, but the European clock-time median and pooled estimate turn negative. Individual zones can also be sensitive to short samples and exceptional price movements: Sicily, for example, changes by 4.5 log points when six earlier transitions are added, largely because of one year in which its baseload price nearly tripled.

These results therefore establish that stratification materially affects whether the quantity-composition gap is recorded; they do not identify a stable European magnitude. Residual-load cells are themselves a diagnostic construction, not uniquely correct output products, and the two system-state variants disagree in sign for IT-SICI and IT-NORD. IT-SUD is negative under every specification and is not explained here. The magnitudes used in the main analysis consequently come from the full current-value measure and its exact composition decomposition, while Table E.2 is interpreted as a test of the aggregation mechanism.

The exercise also clarifies the premise of Section 4.1. A sufficiently granular volume index is capable of registering delivery-time composition. The constraint is not index-number method but the aggregation strata used in official accounts, which distinguish customer classes, tariffs, or destinations rather than hour or system state.

The sensitivity of these comparisons to the 2021–2023 price shock is examined in Section E.7.

E.7 Sensitivity to the 2021–2023 price shock

Because T"ornqvist weights depend on cell revenue shares, exceptional changes in the hourly price distribution may affect the estimated gaps. Table E.3 therefore repeats the European comparison after excluding the 2021–2022 and 2022–2023 transitions, and then also the 2020–2021 transition.

The ordering across stratifications survives the exclusions. The European residual-load median remains positive and above the clock-time median in every sample, while ERCOT continues to show a substantially larger gap under residual-load strata. This supports the mechanism that clock-time cells can miss wind variation across days within the same hour-of-delivery cell.

The level estimates are not robust. Once the shock transitions are removed, the European clock-time median and pooled index turn negative, and the number of positive clock-time estimates falls sharply. The chained-index exercise therefore shows that stratification materially affects whether the quantity-composition margin is recorded; it does not identify a stable European magnitude. The restricted samples are also shorter and exclude years of rapid renewable deployment, so the full panel remains the principal specification.

Taken together, the results show that a sufficiently granular volume index can register delivery-time composition, although the estimated magnitude is sensitive to the chosen strata and sample period. The constraint in official measurement is therefore not index-number method itself, but aggregation strata that distinguish customer classes, tariffs, or destinations rather than hour or system state.

F Calibration of the crossover

This appendix documents the calibration behind Figure 3. The exercise compares the capital-price bias and the output-value bias over a common path of wind-and-solar penetration. Both biases are expressed as annual contributions to whole-sector TFP. The object of interest is the penetration $\theta^\star$ satisfying

$$B_K(\theta^\star) = B_V(\theta^\star). \tag{S.43}$$

The exercise identifies a penetration threshold under alternative calibrations; it does not forecast the date at which any system reaches that threshold.

Mapping annual biases into penetration. Both objects in the crossover exercise are annual growth-rate biases:

$$B_{K,t} = s_K\,\omega_{R,t}\,\gamma_{K,t}, \qquad B^{\text{gen}}_{V,t} = -\Delta_t \log(1 - D).$$

To express them against a common penetration axis, I evaluate both along the logistic path

$$\theta_t = \frac{\theta_{\max}}{1 + \exp[-r(t - t_0)]}.$$

Conditional on this ceiling, the growth rate r and midpoint t_0 are chosen so that the path passes exactly through the EU wind-and-solar shares of 0.05 in 2010 and 0.29 in 2024. This gives $r = 0.149$ per year and $t_0 = 2029.0$. The path supplies the penetration level associated with each annual capital bias and, for the output-value bias, the annual change from θ_{t-1} to θ_t. The reported crossover $\theta^\star$ is therefore conditional on the assumed saturation ceiling and the resulting EU deployment path.

I impose a saturation ceiling of $\theta_{\max} = 0.90$ following Jakhmola et al. (2026), it assumes an early and late acceleration scenario, where the ceiling L is respectively 92% (45% for wind, and 47% for solar), and 94% assumes L = 45% (47% for wind, and 47% for solar). For sensitivity analysis, I test whether a 80% ceiling for renewables would alter the result and find that the cross-over penetration rate θ^* is robust to the ceiling assumption (Table F.1).

But the crossover asks what happens at penetrations not yet observed, hence it requires a relationship between each technology's value factor and its penetration. To calculate D_t, I need an assumption about how each value factor changes as penetration rises:

$$v_j(\theta_j) = v_{0,j} - a_j\theta_j,$$

where a_j is the cannibalization rate of the technology j, that how much technology j's value factor falls as its penetration increases,

$$a_j \equiv -\frac{\partial v_j}{\partial \theta_j} > 0.$$

The cannibalization rates are not used to construct the observed gap in Figure 2; they are needed only to project the output-value bias and locate the forward crossover. Namely, with the value of a_j, I have

$$D(\theta) = \theta(1 - v_0 + a\theta),$$

and

$$D'(\theta) = 1 - v_0 + 2a\theta.$$

A larger a makes the gap accelerate more sharply with penetration and therefore makes B_V rise sooner. That is why a solar-heavy installation schedule will cross the capital curve earlier.

Figure 2 cannot help to assess the cannibalization rate, as it only documents the realized level of the output-value gap. Because penetration enters D directly, the upward relationship in the figure combines the effect of greater renewable penetration θ_j with any decline in value factors v_j as penetration rises and doesn't allow to distinguish.

I calibrate a_j using the cross-border estimates of Stiewe et al. (2025), which incorporate both domestic and neighbouring penetration (Table F.2). As a diagnostic, Supplemental Appendix E.3 reports estimates using own-zone variation in the ENTSO-E panel. They have the expected sign but are imprecise and substantially smaller; because the domestic specification omits neighbouring penetration, it does not identify the same cross-border effect.

The three scenarios in the last row of Table F.2 differ only in the assumed wind–solar composition of future deployment, which is what the band is meant to bracket. Because the blend slope weights each technology by the square of its share and solar cannibalises its own value roughly three-and-a-half times faster than wind ($a_{\text{solar}} = 3.88$ against $a_{\text{wind}} = 1.09$), the aggregate slope is sensitive to the mix. The lower edge, $a \approx 0.99$, takes the current European mix (2024 Ember:

about 61% wind and 39% solar of wind-plus-solar generation), which is wind-tilted and therefore flatter; the upper edge, $a \approx 1.57$, takes a solar-dominated future (60% solar), which cannibalises faster, thus leading the output-value bias to dominate the capital-deflator bias at a lower penetration. The central line is not a Stiewe blend but the independent Hirth (2013) estimate, $a = 1.30$, which falls inside the band; I use it as the reference schedule so that the central crossover does not rest on a single extrapolated mix assumption.

Capital-price bias. The forward capital curve is

$$B_K(\theta_t) = s_K \, \widetilde{\omega}_R(\theta_t) \, \gamma_{K,t}, \tag{S.44}$$

where $s_K = 0.70$ is the value-added capital share, $\widetilde{\omega}_R(\theta_t)$ is current-cost renewable-capital exposure, and $\gamma_{K,t}$ is the annual gap between the broad electric-infrastructure deflator and the renewable capacity-cost deflator.

The path for $\gamma K, t$ is anchored to the IRENA installed-cost descent: it starts at the measured solar rate of 15.0% a year, is pinned to the recent three-year blend of 9.8% at $\theta = 0.29$, and decays toward an asymptote $\gamma\infty$. The asymptote is not a free parameter. Learning does not terminate at high penetration; a mature fleet still replaces itself, so cumulative experience keeps growing at roughly $1/L$ with L the asset life, and the price decline settles at $\gamma\infty = b/L = 0.319/30 \simeq 0.011$ per year, using the solar-PV exponent and thirty-year lifespan of Way et al. (2022, Table S24). The crossover is close to invariant to this choice: $\theta^\star$ moves from 0.414 at $\gamma\infty = 0$ to 0.428 at $\gamma_\infty = 0.05$, against a span of 0.07 for the generation weight and 0.20 for the deployment mix. The blend weight behind the anchors, sixty percent solar, matters still less: over weights from 0.40 to a pure-solar 1.00, $\theta^\star$ moves by half a point, because the schedule takes the steeper of the solar and blended rates and solar is steeper throughout.

Renewable-capital exposure is observed only over the relatively low-penetration US range. The measured series ends in 2024 at $\theta = 0.172$, whereas the crossover exercise extends beyond $\theta = 0.5$. I therefore close the unobserved part of the capital curve by setting

$$\widetilde{\omega}_R(\theta) = \theta. \tag{S.45}$$

This is a parameter-free forward assumption, not an estimate of the exposure relationship.

The assumption is conservative for the estimated crossover penetration. In the 2024 US data, the repriced renewable assets account for 11.2% of total sector capital ($\widetilde{\omega}_R = 0.112$; the rental-weighted services exposure is lower still, about $0.79 \, \widetilde{\omega}_R$, Appendix A.3), compared with wind-and-solar penetration of 17.2%. Setting $\widetilde{\omega}_R = \theta$ therefore raises the forward capital curve relative to the observed US exposure-to-penetration ratio and delays the point at which the output-value bias overtakes it. Conditional on future exposure not exceeding penetration, the resulting $\theta^\star$ is an upper calibration on the exposure margin.

The measured US capital biases shown as open circles in Figure 3 use observed total-sector current-cost exposure $\widetilde{\omega}_R$ rather than Equation (S.45). The exposure closure is used only to extend the forward curve and does not enter the historical US reclassification reported in Table 1.

Output-value bias. For each technology $j \in \{s, w\}$, let $\theta_{j,t}$ denote generation penetration and $v_{j,t}$ its value factor. The generation-level output-value gap is

$$D_t = \theta_{s,t}(1 - v_{s,t}) + \theta_{w,t}(1 - v_{w,t}). \tag{S.46}$$

Its annual growth counterpart is

$$B_{V,t}^{\text{gen}} = -\Delta \log(1 - D_t). \tag{S.47}$$

Because the electricity sector also contains transmission and distribution, the object comparable with the sector capital bias is

$$B_{V,t} = w_G B_{V,t}^{\text{gen}}, \qquad w_G = 0.55. \tag{S.48}$$

All crossover calculations use Equation (S.48); no intersection between B_K and the unscaled generation bias is reported.

The forward value-factor paths use the technology-specific responses estimated by Stiewe et al. (2025), with $a_w = 1.09$ for wind and $a_s = 3.88$ for solar. I consider three calibrations. The wind-heavy calibration applies these responses to the current EU wind-and-solar mix. The solar-heavy calibration raises solar's share of wind-and-solar generation to 60 percent. The central calibration uses the Hirth (2013) blend, with an aggregate response of $a = 1.30$. In each case the calibrated value factors enter Equation (S.46), and the resulting generation bias is converted to whole-sector units using Equation (S.48).

Crossover results. For each value-factor calibration, I define the crossover as the first penetration at which

$$w_G B_V^{\text{gen}}(\theta) \geq B_K(\theta).$$

Under the central Hirth (2013) calibration, the two biases cross at approximately

$$\theta^\star = 0.42.$$

The solar-heavy calibration crosses earlier because solar has the steeper value-factor response. The wind-heavy calibration crosses later because its output-value bias rises more gradually. The sensitivity results are reported in Table F.1.

Adaptation. Storage, transmission and flexible demand flatten the net-load value profile and therefore reduce the effective cannibalisation slope. Rather than model those technologies, Table F.1 attenuates the central slope and asks what adaptation would have to deliver: a quarter off a moves the crossover from $\theta^\star = 0.42$ to 0.56, and a half off it defers the crossover beyond the modelled penetration range. The threshold is thus considerably more sensitive to the cannibalisation slope than to the saturation ceiling, which moves it by three points; as with the composition-only column, the reason is the flatness of B_K at high penetration, where a small downward shift in B_V travels a long way along the penetration axis before the curves meet. A quarter off the central slope also happens to land almost exactly on the wind-heavy mix ($a = 0.98$ against 0.99), so those two rows describe nearly the same schedule reached by different routes, one compositional and one behavioural. Two things follow. The forward statements in the main text should be read as conditional on value-factor schedules estimated on a near-storage-free system, and, on the main-text calibration, the omission of flexibility places $\theta^\star = 0.42$ toward the early end of the plausible range. But adaptation on this scale is a postponement, not a removal: storage arbitrage value itself compresses with storage penetration—the same mechanism one step downstream—so the flexibility that flattens the renewable schedule is subject to it too (Supplemental Appendix H).

The generation weight. Because $B_V = w_G B_V^{\text{gen}}$, the generation share of sector gross output scales the entire output-value bias one-for-one, and the crossover inherits that scaling. Neither BEA nor Eurostat splits the electricity industry into generation and delivery—NAICS 2211 and NACE D35 are single industries—so w_G has to be measured from the published price and revenue decompositions. Table F.3 reports three.

The Annual Energy Outlook decomposes the retail electricity price into generation, transmission and distribution components, and the base year of each vintage is observed rather than projected (U.S. Energy Information Administration, 2026b); stacking the base years of AEO2015 through the current release gives a generation share of 0.612 on average over 2012–2025, in a range of 0.559 to 0.655. That estimator divides by retail revenue. Dividing the same EIA generation revenue instead by the BEA gross output for NAICS 2211—the denominator the sector productivity accounts actually use, and the larger of the two—gives 0.585 on average, in a range of 0.523 to 0.648. The European counterpart, the energy-and-supply component of the Eurostat price decomposition net of taxes (Eurostat, 2026a), averages 0.582 before 2021; it is an upper bound, because the energy component bundles the retail supply margin with generation, and after 2021 the gas-price spike inflates it against regulated network charges.

The three estimators share a numerator and differ in the denominator, so they are not three readings of one quantity to be averaged: only the second divides by the gross output for NAICS 2211 on which the sector productivity accounts, and therefore B_K's counterpart in this comparison, are built. The calibration accordingly maintains $w_G = 0.585$ and takes its band from that estimator's own range, $[0.52, 0.65]$. Three checks support it. The price share rescaled by the measured ratio of retail revenue to BEA gross output, $0.612 \times 0.947 = 0.585$, reproduces it, as the arithmetic requires. Pooling the years rather than averaging nine vintage ratios gives 0.581. And the estimator is centred on its own range, $(0.523 + 0.648)/2 = 0.586$, so the base is not a point chosen inside a span. The estimator is, if anything, a mild lower bound: its numerator counts generation value once, embedded in retail revenue, while BEA gross output includes intra-industry sales, so the ratio of retail revenue to gross output falls from 0.97–1.00 in 2012–2017 to 0.85 in 2022 as wholesale trading value rose. Understatement is the safe direction, since a larger generation weight brings the crossover forward. Over the measured range the central crossover moves from 0.43 to 0.37, against 0.40 at $w_G = 0.585$; the window-to-window variation within the estimator (a mean of 0.607 over 2012–2019 against 0.540 over 2019–2022) sits inside that band. This remains a smaller lever than either the deployment mix or adaptation. One limitation: the deployment path is European while w_G is American, and no concept-matched European estimator exists, because NACE D35 carries no generation/delivery split — which is why the European row is a price decomposition and enters as a bound.

G Cross-country harmonization: US-anchored exposure and the convention gap

The unobserved exposure problem. The capital-price correction depends on renewable-capital exposure,

$$\widetilde{\omega}_R \equiv \frac{K_R}{K_D},$$

where K_R is the current-cost stock of the renewable assets affected by the deflator change and K_D is total sector capital. European national accounts do not separately identify renewable and conventional electric-power capital within NACE Section D. European exposure must therefore either be constructed indirectly or calibrated from a system in which the relevant capital split is observed.

Diagnostic European constructions. I construct a renewable-capital numerator by valuing Ember wind and solar capacity at IRENA installed-cost benchmarks and accumulating investment under a perpetual-inventory rule with depreciation $\delta = 0.04$. The resulting exposure levels depend materially on the valuation basis used for the total-sector denominator.

On this vintage the penetration shortcut overstates input-side exposure for every system reported, most sharply for Denmark, whose high penetration coexists with low constructed exposure. But the construction is not stable. Repeating it on the matched 2010–2017 window against Eurostat net book values—rather than current replacement cost—inverts the picture: the ratio $\widetilde{\omega}_R/\theta$ then ranges from 0.58 in Denmark to 6.49 in France, with Germany at 4.74 against 0.56 on the current-cost vintage. The French and German estimates are not credible as measures of renewable assets' share of total sector capital, particularly given France's low wind-and-solar generation share over that window. They diagnose a valuation mismatch: the renewable numerator is measured at estimated current replacement cost, whereas the Eurostat net book denominator carries a long-lived capital stock at depreciated historical cost, so the ratio is inflated by a basis difference rather than by any feature of European capital. An order-of-magnitude swing in the same country across two defensible constructions is why the harmonization below is anchored to the one system in which the split is measured, and why constructed European levels are not inserted directly.

The US anchor. The United States is the only system with a measured renewable/conventional capital split. Over 2011–2017 the BEA data give a mean exposure-to-penetration ratio of $\widetilde{\omega}_R/\theta = 1.00$; by 2024, with penetration at 0.172 and exposure at 0.112, the ratio is 0.65. I therefore write European exposure as $\widetilde{\omega}_R = \phi\theta$ and report a band $\phi \in [1, 2]$: $\phi = 1$ imposes the measured US relationship, and $\phi = 2$ is a deliberately conservative stress in the upward direction suggested by the matched-window construction for Germany, although that construction is not treated as a credible level estimate..[14]

The annual rule. At the measured US deflator gap, the bias per unit of exposure follows directly from Equation (2). With $s_K = 0.70$ on a value-added basis, ten percentage points of renewable-capital exposure imply

$$0.70 \times 0.10 \times \gamma_K = \begin{cases} 0.60 \text{ pp/yr}, & \gamma_K = 8.5\% \text{ (smoothed 2010–2024 bias)}, \\ 0.77 \text{ pp/yr}, & \gamma_K = 11.0\% \text{ (recent annual value)}, \end{cases}$$

that is, approximately 0.6–0.8 percentage points of measured sectoral TFP growth per year. This is the rule quoted in Section 5.

The EU–US convention gap. A system still deflating renewable investment with broad construction indexes books renewable-capital learning as TFP; the post-2023 United States books approximately none of it. The published gap therefore contains a pure convention component equal to the B_K the European accounts have not yet removed. Cumulating $B_{K,t} = s_K\phi\theta_t\gamma_{K,t}$ along the EU deployment path over the fourteen growth years 2011–2024 gives approximately 14 cumulative log points at the measured anchor $\phi = 1$ and approximately 28 at the $\phi = 2$ stress, on the value-added capital share $s_K = 0.70$ used above; the LCOE-based upper share $s_K = 0.85$ raises these to 17 and 34.[15] Both figures are sectoral. The Domar weight is irrelevant here, because the comparison being corrected is itself a sectoral one.

The Germany–US Section-D gap. The same correction applied to the matched EU KLEMS Section-D window is reported in Table G.2. Published KLEMS TFP growth is −1.31% per year for

[14] This ϕ is unrelated to the $\kappa \equiv s_K\omega_R$ of Supplemental Appendix B.

[15] Computed from the Ember EU wind-and-solar share and the measured annual deflator gaps; see `Results/provenance_gap_closure.md`. The bias is linear in s_K, so the two share conventions scale it proportionally.

Germany against -1.59 for the United States, so Germany leads by 0.28 points. The US-anchored correction removes between 0.47 and 1.21 points per year of that lead, turning it into a deficit of 0.19 points at $\phi = 1$ and 0.93 at $\phi = 2$. Over the seven growth years 2011–2017—equivalently, the 2010–2017 endpoints—this cumulates to 3.3–8.5 log points of the published Germany–US difference attributable solely to the deflator convention.

The point estimates reverse the Germany–US ordering, but the corrected gap of roughly 0.2 percentage points per year at the measured anchor is smaller than the uncertainty in the imported γ_K the capital shares, and ϕ. The correction therefore makes the published ranking fragile but does not establish that the underlying ranking is reversed. The claim the paper makes is that published rankings are sensitive to the renewable-capital correction, not that they reverse.

H Storage as a second member of the self-correlated class

The paper's class claim is that any technology whose output is self-correlated pushes measurement bias from input prices toward output value as it scales. Grid-scale storage provides a second member, observable in US data. A battery's service is intertemporal arbitrage; its per-unit value is the price spread it straddles; and, like a solar MWh, that value is eroded by neighbours doing the same thing, because charging in the trough and discharging at the peak compresses the trough-peak spread itself.

Storage also has an input-side analogue. Battery costs have followed a steep learning curve (Way et al., 2022), so a broad capital deflator could misclassify embodied progress in storage investment in the same way as for renewable generating equipment. The paper does not quantify this additional capital-price bias; the point here is only that storage can be subject to both sides of the measurement problem.

CAISO provides the test. Operating battery power in the CAISO balancing area grew from 0.5 GW in 2020 to 15.4 GW in 2025. Regressing the monthly mean intraday arbitrage spread (top four hours minus bottom four hours of day-ahead prices, April 2023 to 2025) on log storage penetration with month-of-year fixed effects gives an elasticity of -0.73 (SE 0.15, $t = -4.8$): conditional on seasonality, doubling the fleet compresses the per-unit arbitrage value by about half. Because the spread is a fuel-cost differential across hours, the natural-gas price scales it mechanically and could in principle drive this slope; gas was also volatile over the window. It does not: adding the log monthly Henry Hub gas price to the regression leaves the storage elasticity essentially unchanged at -0.74 (SE 0.19, $t = -3.8$), with the gas coefficient itself insignificant ($t = 0.1$) once month-of-year effects absorb the seasonal fuel cycle, and battery penetration and gas only moderately collinear (correlation 0.57). Indeed gas rose through 2025 while the spread kept falling, so a falling fuel price cannot account for the compression. The same distinction between a conditional value object and the fuel-driven price level separates the value factor from the fuel-driven PPI in Supplemental Appendix D.

The mapping into the accounting is identical in form to Proposition 2, with θ the storage share and v the realized-over-initial spread ratio. Storage is still small in output terms, so this is a class illustration rather than a quantitatively material bias; its role in the argument is twofold. It converts the class from an assertion into a two-member falsifiable pattern, and it bounds the adaptation escape valve of Section 5: the flexibility that flattens the renewable value-factor schedule is itself subject to the same self-cannibalization, so adaptation defers the crossover rather than removing it. The estimate rests on thirty monthly observations from one ISO and should be read as preliminary.

I Official sources

This appendix records the document-specific methodological details drawn from official sources, so that they remain visible without appearing as annotations in the reference list. The bibliography entries for these sources contain publication metadata only.

I.1 Bureau of Economic Analysis

Private fixed investment and the electric-power deflators. The general framework for private fixed investment is described in the NIPA Handbook, including the source-and-method summary in Table 6.A (Bureau of Economic Analysis, 2024b, Table 6.A). For electric-power structures, three sources establish the relevant chronology. First, the June 2023 preview of the comprehensive update announced a separate "alternative electric" price index for wind and solar structures, constructed as a weighted composite of EIA average construction costs in dollars per kilowatt and applied retrospectively from 2010. The same document states that traditional and alternative electric structures had previously been deflated together with a composite of Handy–Whitman electric-power and utility-building construction-cost indexes (McCulla et al., 2023). Second, the November 2024 methodology summary identifies the source indexes used for alternative and other electric-power structures (Bureau of Economic Analysis, 2024c). Third, the 2025 annual update records a separate change for "other electric power structures": beginning in 2024:Q1, the source moved from Handy–Whitman to Bureau of Reclamation construction-cost data (Mataloni and McCulla, 2025). In BEA's June 2023 SCB preview (McCulla et al., 2023):

> ***Improved prices for private fixed investment in wind and solar power structures within electric power structures*** *Beginning with 2010, BEA will introduce a new price index to deflate wind and solar power structures within its estimates of real private fixed investment in electric power structures. Additionally, measures of wind and solar power structures will be presented separately in NIPA underlying table group 5.4.xU. Currently, traditional and alternative power structures are measured and presented as a single series; they are deflated using the same price index, which is based on a composite of Handy Whitman's electric power and building construction cost indexes. However, Handy Whitman's cost indexes do not cover construction cost data for alternative electric power structures; as a result, the indexes do not reflect the significant price decreases in wind and solar structures over recent years. As part of this year's update, wind and solar power structures will be deflated using a new composite price index based on a weighted composite of the Energy Information Administration's average annual costs of construction for wind and solar generators (measured in dollars per kilowatt of installed nameplate, or maximum, capacity).*

The published alternative-electric series is a Fisher price index in NIPA underlying Table 5.4.4U, series `IA001174-A`. The values used for the latest-vintage check are 78.104 in 2023 and 70.870 in 2024 (Bureau of Economic Analysis, 2026). Handy–Whitman is a proprietary trade-source family rather than a published formula (Whitman, Requardt and Associates, LLP, 2026). Reclamation's Construction Cost Trends are composite construction-cost indexes whose current movements are driven chiefly by BLS producer price indexes, supplemented by other price sources and engineering judgment (U.S. Bureau of Reclamation, 2026). This later source change remains within the broad construction-cost family and does not alter the paper's identified comparison, which reprices renewable investment while holding the conventional-capital series fixed.

Depreciation parameters. The source for the perpetual-inventory parameters is BEA's table "BEA Rates of Depreciation, Service Lives, Declining-Balance Rates, and Hulten–Wykoff Categories" (Bureau of Economic Analysis, nda). The parameter choices used in the capital-services calculation are described where they enter the analysis in Supplemental Appendix A.4.

Industry and household electricity output. For the industry accounts, BEA constructs chain-type quantity indexes for gross output by deflating the current-dollar commodity composition of an industry's output with corresponding commodity price indexes and combining the resulting commodity quantity indexes; real value added is obtained by double deflation and Fisher aggregation (Bureau of Economic Analysis, ndb). For household electricity, the 2024 NIPA Handbook describes current-dollar personal-consumption estimates based on EIA residential revenue, with quantity and price information from EIA kilowatt-hours and cents per kilowatt-hour, adjusted by BEA from a billing to a usage basis, together with the BLS electricity CPI (Bureau of Economic Analysis, 2024a, Ch. 5). Because that handbook reflects the 2024 annual update, the current source-data description is the 2025 methodology summary: annual EIA electricity quantities are combined with BLS CPIs for personal consumption, while monthly EIA physical quantities combined with BLS PPIs are used for the electric-utility components of government consumption and private inventories (Bureau of Economic Analysis, 2025).

Access dates. The Table 5.4.4U series was accessed on May 11, 2026. The 2023 preview and 2025 annual-update pages were accessed on July 21, 2026. The output-methodology sources were accessed on July 28, 2026.

I.2 Bureau of Labor Statistics

The bibliography entries for the BLS sources contain publication metadata only. This subsection records the document-specific methodological details used in the paper.

Industry productivity output. The BLS industry productivity program defines sectoral output as the goods and services produced by an industry for sale to consumers or to businesses outside that industry. Real output is generally obtained by deflating nominal sales or values of production with BLS price indexes. For some industries, including parts of the utilities sector, it is instead measured directly from physical quantities. Where the necessary product detail is available, BLS constructs physical-quantity output indexes as Törnqvist aggregations of individual products. Under the deflated-value method, revenues are deflated at the detailed product-class level to account for changes in product mix; BLS describes the resulting indexes as conceptually equivalent to indexes constructed from physical quantities (Bureau of Labor Statistics, 2017).

Electric-utility productivity output. The documented BLS method for electric utilities bases output on kilowatt-hours sold to ultimate consumers rather than kilowatt-hours generated. Sales to each class of service are weighted by the price associated with that service class. This weighting is intended to prevent shifts in the distribution of sales among customer classes from appearing spuriously as productivity changes. Inter-utility sales are excluded from both output and input. The technical note states its coverage using the former SIC classification, including SIC 491 and the electric operations of combination utilities in SIC 492–493, and identifies the Energy Information Administration as the source of the underlying sales data (Bureau of Labor Statistics, nd).

Producer price indexes. The BLS Producer Price Index measures the net revenue received by a specified producing establishment from a specified buyer for a specified product or service under specified transaction terms. BLS seeks actual transaction prices, including applicable discounts, premiums, rebates, and allowances, rather than list or book prices. Its methodology also provides for quality adjustment when the sampled product, transaction terms, or unit of measure changes (Bureau of Labor Statistics, 2026b).

For electric power generation, NAICS 221110, the industry PPI measures price changes for the initial commercial transaction received by generating establishments and distinguishes generation by utilities from generation by non-utilities. For bulk transmission and control, NAICS 221121, the index measures changes in transmission and control fees and charges. Separate distribution indexes within NAICS 221122 cover residential, commercial, and industrial electricity; these series extend back to December 1990 (Bureau of Labor Statistics, 2005).

Household electricity prices. In the CPI, BLS prices electricity under separate rate-schedule specifications, including general residential, heating, non-heating, and water-heating service. The consumption amounts attached to the sampled rate schedules are selected using probability procedures based on consumption averages supplied by the Department of Energy. BLS also publishes average electricity prices per kilowatt-hour. Those series are dollar levels and should not be confused with the CPI electricity index (Bureau of Labor Statistics, 2026a).

Access dates and document vintage. The BLS Handbook of Methods pages and the two electricity price fact sheets were accessed on July 28, 2026. The electric-utility productivity technical note is entered under 2007, corresponding to its stated revision date; a claim that depends on a particular document vintage should refer to the date shown in the technical note itself.

I.3 Energy Information Administration

Form EIA-861 reports electricity sales to ultimate customers, associated revenue, and customer counts by state and customer class. The data distinguish bundled service, energy-only service, and delivery-only service. EIA's reported average retail price of electricity is calculated as reported revenue divided by reported kilowatt-hours sold. It is therefore an average-revenue or unit-value statistic, rather than a fixed-specification price index (U.S. Energy Information Administration, 2026a).

The precise field definitions and service-type classifications should be read together with the instructions for the applicable Form EIA-861 reporting vintage. The source was accessed on July 28, 2026.

I.4 Eurostat

Eurostat, Handbook on prices and volume measures in national accounts, 2016 edition (Publications Office of the EU; ISBN 978-92-79-37859-1), §4.4 "CPA D — Electricity, gas, steam and air conditioning," pp. 79–80. The recommended "A method" for production: (Eurostat, 2016)

> "The A method here is to deflate value of output by the available PPIs... A fully equivalent approach, which would also be an A method, is to directly use the quantity data available on products, providing the quantity data is sufficiently detailed."

ESA 2010 §10.32 (ESA 2010) (quoted in the Handbook, ch. on value added): "the theoretically correct method to calculate value added in volume terms is by double deflation, i.e. deflating separately the two flows of the production account (output and intermediate consumption)..."

The Handbook explicitly names the intraday-value problem and instructs statisticians to treat it as a quality difference, i.e. as different products, not a value change (§4.4, p. 79, citing ESA 2010 §10.16): (ESA 2010)

> "a clear distinction is drawn between price differences based on quality (for example electricity supplied at night compared with supply during the day... or there may be a different tariff for 'green' electricity) and price discrimination."

I.5 Federal Reserve Board

The physical-output benchmark for NAICS 2211 is the Federal Reserve's industrial-production index for electric power, series `IPG2211A` of the G.17 statistical release, annual and indexed to 2017=100 (Board of Governors of the Federal Reserve System, 2026). The generation-only and technology splits used in Figure D.1 are `IPG22111A` (generation, NAICS 22111), `IPN221114T8A` (renewable and other) and `IPN221112A` (fossil). This is a quantity index built from physical energy data rather than a deflated value, which is why it serves here as the physical counterpart to the BLS deflated-output series. Two differences from the BLS sectoral-output concept should be kept in view: the Federal Reserve index measures generation rather than sales to ultimate customers, and it is partly weather- and workday-adjusted. Neither series resolves the hour of delivery, which is the margin at issue. The series were retrieved through FRED, which mirrors the release, on July 17, 2026.

I.6 Lawrence Berkeley National Laboratory

The independent US installed-cost series in Figure 1 and Figure A.4 are taken from a single 2025 vintage of two Berkeley Lab market reports, so that both technologies rest on one consistent basis. Utility-scale solar is the capacity-weighted average installed cost of ground-mounted photovoltaic plants above 5 MW-AC, from the tab "CapEx Trend (PV-only)" of the data file accompanying Seel et al. (2025); land-based wind is the capacity-weighted average installed cost of land-based projects, from the tab "CapEx Over Time" of the data file accompanying Wiser et al. (2025). Both are published in real dollars and are converted to a nominal basis with the BEA implicit GDP price deflator wherever the comparison is against the BEA deflator, which is nominal. The 2024 observation is EIA-preliminary for both technologies, and the wind sample is thin in 2013, 2022 and 2024; this is why the settled 2010–2023 window is the reported comparison in Section A.6. The capacity weights for the Törnqvist composite are annual gross additions from the same two reports, solar from Berkeley Lab and EIA and wind from ACP, a provider difference inherent to the two publications. The equipment-import and turbine-price evidence in Section B instead uses the 2024 edition of the wind report (Wiser et al., 2024), whose data file carries the import series.

I.7 Ember

The observed penetration path $\theta(t)$ for the European Union, Germany and the United States is the "Wind and Solar" share of total electricity generation, in percent, from the yearly full release of Ember's *Yearly Electricity Data* (Ember, 2025). The 2024 values anchoring the system positions in Figure 3 are 0.288 for the European Union, 0.435 for Germany and 0.172 for the United States. The same release supplies the capacity series used for the sourcing shares in Section B and the physical generation in Figure D.1. Ember compiles from EIA, Eurostat, ENTSO-E and national statistical sources rather than collecting primary data, so it is used here as a harmonised cross-country access layer; as a level check, its global solar capacity at end-2024 is within one percent of the IRENA figure. Accessed June 22, 2026.

I.8 ENTSO-E

The European bidding-zone panel is built from the ENTSO-E Transparency Platform (ENTSO-E, 2026): hourly day-ahead prices (Article 12.1.D), actual generation per production type (Article 16.1.B&C) and actual total load (Article 6.1.A), retrieved through the Web API for 15 bidding zones over 2015–2024. Penetration on this panel is generation over total generation, not generation over load; the two differ for net-trading zones, of which West Denmark (bidding zone DK1) is the clearest case, and the generation basis is the one under which the gap $D = \theta_s(1 - v_s) + \theta_w(1 - v_w)$ equals the proportional shortfall of value-weighted relative to physical generation exactly. On this basis DK1 reaches $\theta = 0.751$ in 2024, which is the position reported for West Denmark in the main text; the whole-country Danish figure of 0.692 in Table G.1 is a different aggregate and is not comparable. Negative prices are retained. Accessed July 16, 2026.

J Material removed in this revision

This section collects, verbatim, the substantive text removed from the previous draft of the supplemental appendix, so that nothing disappears silently. Each item notes why it was removed. Delete this section before submission.

J.1. "Old main section" of the official-statistics appendix

Removed because its content is now fully covered by main-text Section 4.1 and by Appendices D.1–D.11; the US 2017–2024 numerical check appears in main-text Section 4.1 and in Appendix D.6.

> Before measuring B_V, it must be established that the official output account does not already register the relevant change in value. The claim required is precise, and it is not a claim about deflators. Official real electricity output is built in one of three ways. The BLS industry productivity program measures utilities output either as a physical quantity index — in its documented electric-utility method, a Törnqvist index of kilowatt-hours sold to ultimate customers, weighted by class-of-service prices — or by deflating current-dollar output at the product-class level (Bureau of Labor Statistics, 2017, nd). The BEA industry accounts deflate the commodity composition of gross output with chain-type indexes built from electric-power producer prices (Bureau of Economic Analysis, ndb), while the household component of personal consumption is a quantity extrapolation from EIA kilowatt-hours (Bureau of Economic Analysis, 2025). The harmonised European framework admits the same two families as equivalent A-methods: deflation of output values by a suitable producer price index, or direct quantity extrapolation sufficiently detailed by tariff and customer type (Eurostat, 2016, §3, CPA 35); the United Kingdom and Norway implement the direct-quantity branch, building short-term electricity volumes from physical energy data rather than deflated turnover (Office for National Statistics, 2024; Bougroug, 2021).
>
> What all these constructions share is the property Proposition 2 requires: the strata of the volume aggregation are customer classes, tariffs, or markets of destination — never the hour and location of delivery. Within each stratum-year, every MWh enters with the same weight, regardless of whether it was produced in a scarce evening hour or a saturated midday hour. ESA 2010 itself recognises time of delivery as a quality margin in principle, naming night versus day electricity as potentially distinct products (ESA 2010, §10.16), so the measurement gap is a granularity gap in the instruments implementing the standard, not a conceptual dispute with it. For the deflated-value branch the statement must be an accounting condition rather

than a property of the price index alone: a deflator that ignores capture prices leaves the bias in the published series only to the extent that the capture-value loss also fails to reach recorded nominal output. Supplemental Appendix D states this condition, documents each construction from current agency methodology, and shows that the bias survives in every case — unconditionally under direct-quantity and extrapolation methods, and scaled by one minus the settlement pass-through under deflated value, which the tariff, contracting, and regulatory structure of US retail supply holds low.

The account is correct not to distinguish electricity by generation technology. Conditional on the hour and location of delivery, a MWh is a homogeneous energy product, and its value does not depend on whether it was produced by wind, solar, nuclear, or gas. Deflating source-specific output by source-specific production costs would use an input-cost index as an output deflator and credit falling renewable costs as real output growth (Supplemental Appendix C.3). The relevant heterogeneity is across hours and locations.

The US series provide a direct check at the level entering the productivity residual, all electric power (NAICS 2211). Between 2017 and 2024, nominal sector output rose by 25.3% and the output price deflator by 25.5 percent. Their ratio — official real output — was therefore essentially flat, falling by 0.1 percent, while the Federal Reserve's physical-output index rose 6.3% over the same period. The official measure thus failed to register the increase in physical electricity supplied, and neither series resolves the time-of-delivery margin (Supplemental Appendix D.6). This creates the same identification problem encountered on the capital side, with a different solution. B_K cannot be inferred from changes across official TFP vintages because other inputs were revised at the same time. Similarly, B_V cannot be recovered by manipulating annual output aggregates because the relevant hourly and locational information has already been averaged out within the published strata. It must instead be constructed directly from hourly market prices and generation.

The argument yields a direct test. If the bias reflects the omission of hour and location from the aggregation strata, it should emerge when those dimensions are introduced while holding the underlying observations and index formula fixed. Section 4.2 implements this test: applied to the same hourly data, the same superlative index produces a material bias when products are defined by clock time or system state, but none when the strata resemble those used in official accounts.

J.2. Duplicate "Electricity-sector residual" calibration with alternative κ range

Removed from Appendix B as a duplicate of the preceding paragraphs with different numbers ($B_K^{\text{off}} \simeq 4.8$–$6.3$, $\kappa \in [0.0402, 0.0528]$, against 4.3–7.1 and $[0.0360, 0.0595]$ in the retained version). The retained version matches the notes to Table B.2. Verify against the code which range is current before deleting.

Let $\gamma_K = \Delta \ln P^{\text{broad}} + D$, where the broad electric-plant deflator rises by 52.8 log points over the period. Under import sourcing, $\gamma_K^{\text{off}} = 52.8 + 66.5 = 119.3$ log points. The corresponding electricity-sector value-added residual is

$$B_K^{\text{off}} = s_K \omega_R \gamma_K^{\text{off}} \simeq 4.8\text{–}6.3$$

log points.

It is useful to collect the combined exposure term as $\kappa \equiv s_K \omega_R$. The measured range implies

$$\kappa \in \left[\frac{4.8}{119.3}, \frac{6.3}{119.3}\right] = [0.0402,\ 0.0528].$$

Under full US reshoring, the deflator gap falls to $\gamma_{K,\text{US}}^{\text{re}} = 52.8 + 15.7 = 68.5$ log points, so that

$$B_{K,\text{US}}^{\text{re}} = \kappa(68.5) \simeq 2.8\text{–}3.6$$

log points. Relative to import sourcing, the residual therefore falls by

$$\begin{aligned} B_K^{\text{off}} - B_{K,\text{US}}^{\text{re}} &= \kappa(66.5 - 15.7) \\ &= \kappa(50.8) \\ &\simeq 2.0\text{–}2.7 \end{aligned}$$

value-added log points.

Under full EU reshoring, $\gamma_{K,\text{EU}}^{\text{re}} = 52.8 + 19.6 = 72.4$ log points, which gives

$$B_{K,\text{EU}}^{\text{re}} = \kappa(72.4) \simeq 2.9\text{–}3.8$$

log points. The corresponding compression is

$$B_K^{\text{off}} - B_{K,\text{EU}}^{\text{re}} = \kappa(66.5 - 19.6) = \kappa(46.9) \simeq 1.9\text{–}2.5$$

value-added log points.

These calculations are the numerical counterpart of

$$B_K^{\text{off}} - B_K^{\text{re}} = s_K \omega_R b \ln\left(\frac{Q_g}{Q_d^{\text{re}}}\right).$$

J.3. "Why the quality principle does not remedy this" (from the Eurostat sources subsection)

Removed as argument rather than source documentation. Its permissive-versus-required point is folded into Appendix D.8; its fixed-base-versus-current-value distinction duplicates the opening of Appendix E.6.

> **Why the quality principle does not remedy this.** One might object that the harmonised framework already provides for the bias. In principle it does. If the output account resolved electricity by hour of delivery—treating a nine-o'clock megawatt-hour and a one-o'clock megawatt-hour as distinct products, each carried at a fixed base-period price, and aggregating quantities across them—the resulting volume index would be revenue-weighted across hours. A shift of generation toward low-value midday hours would then lower measured volume even with annual megawatt-hours unchanged, because the cells losing output carry larger revenue weights than the cells gaining it. That is exactly the quantity-composition margin described below, and an account built this way would not miss it.
>
> Two qualifications keep such an index distinct from the benchmark used in the empirical work. First, it registers composition and not the level of relative prices: at unchanged cell quantities, a fall in the midday price relative to the evening price moves the revenue weights but records no change in volume. Second, the benchmark Q_t^{val} of Section 2 evaluates the relative value factor at current-period prices and therefore moves on that second margin as well. The two coincide only where v_t is constant. The fixed-base hourly volume index is thus the narrower object, and in the measured panel the bias against it is the smaller of the two.
>
> The European standard nonetheless endorses the hour-resolved treatment. ESA 2010 classifies time-of-day variation as a quality rather than a price margin, and the compilation handbook gives "electricity supplied at night compared with supply during the day" as its leading example of a quality difference that "can be treated as different products" (ESA 2010, §10.16, Eurostat 2016, §4.4). The concept in this paper and the concept in the standard coincide. What differs is that the treatment is permissive rather than required: the handbook's best-practice condition for a quantity-based volume measure is only that it identify quantities "by tariff and customer type," in which hour of delivery does not appear. The bias is a gap between what the standard contemplates and what the instruments are required to deliver, not a

J.4. Duplicate Bureau of Economic Analysis subsection

The sources appendix contained two near-identical BEA subsections (including a duplicated `tab:nipa_deflation` *label). The merged version retains the chronology paragraph, the source-document table, the 2023 SCB preview quotation, the deflation-methods table with citations, the series identification (*`IA001174-A`*), and the depreciation, output, and access-date paragraphs. Dropped as redundant: the raw NIPA-methodologies quotation and two shorter preview quotations (paraphrased in the retained table and notes), and the longer Construction Cost Trends description (condensed into one sentence, with the point that the post-2024 conventional-line source change is immaterial to the identified* B_K *retained).*

J.5. Empty placeholder "old 4.2"

An empty subsection containing only a blank quotation block; nothing to preserve.

Table E.2: Quantity-composition gaps under alternative delivery-time stratifications, 2015–2024 (Europe) and 2018–2025 (United States). $B_V^{\text{cell}} = \Delta \log Q^{\text{phys}} - \Delta \log Q^T$, where Q^T is a chained Törnqvist volume index. The first three columns apply that index to the same hourly prices and generation, varying only the aggregation strata: residual-load deciles, residual-load deciles interacted with quarter, and month-by-hour-of-delivery cells. Residual-load breakpoints are fixed within each zone using the pooled distribution, so that cells are comparable across years. The final column reports the current-value bias $B_V^{\text{gen}} = -\Delta \log(1 - D)$ over the same transitions, computed from the same hourly observations. n is the number of annual transitions, which differs across zones, so cumulative figures are not comparable across rows without it. Rows are ordered by B_V^{gen}. Zone-specific cumulative log points, generation basis. The ordering clock-time $<$ system-state survives excluding the transitions spanning the 2021–2023 gas-price shock; the levels do not (Supplemental Note E.7).

		System state		Clock time	Current value
Zone	n	Deciles	Deciles × quarter	Month × hour	B_V^{gen}
Europe (ENTSO-E), 123 transitions					
DK-1	9	+4.28	+5.48	+0.08	+11.53
DK-2	9	+2.77	+1.63	−0.30	+10.48
ES	9	+1.76	+1.03	+0.05	+8.16
DE-LU	5	+2.21	+5.03	+2.44	+7.99
BE	9	+3.48	+2.95	+3.71	+7.55
AT	5	+0.37	+2.11	+3.06	+4.01
IT-SICI	9	+0.37	−2.74	−3.29	+3.11
IT-SARD	9	−0.16	−0.40	+0.25	+2.99
NL	9	+1.39	+1.83	+0.25	+2.62
FR	9	+1.33	+0.27	+1.84	+2.24
IT-CSUD	9	+0.02	+1.20	+1.00	+1.98
IT-CNOR	9	+0.72	+0.08	+0.22	+1.16
GB	5	+0.66	+1.45	+0.01	+1.11
IT-NORD	9	+0.76	−0.51	+0.61	+0.93
IT-SUD	9	−4.50	−4.77	−3.40	−0.80
Median		+0.76	+1.20	+0.25	
Positive		13/15	11/15	12/15	
United States, 12 transitions					
CAISO	5	+6.87	+5.33	+6.23	+8.20
ERCOT	7	+7.21	+9.38	−1.65	+2.89

Table E.3: Sensitivity of the European stratification results to the exclusion of price-shock transitions. Entries are cross-zone medians of cumulative log points, counts of positive zone estimates, and the pooled chained index over zone-by-month-by-hour cells.

	Full panel	Excl. 2021–23	Excl. 2020–23
Transitions	123	95	81
Median: residual-load deciles	+0.76	+0.89	+0.66
Median: deciles × quarter	+1.20	+0.83	+0.48
Median: month × hour	+0.25	−0.30	−0.39
Positive: residual-load deciles	13/15	12/15	10/15
Positive: month × hour	12/15	6/15	5/15
Pooled hour-location index (Europe)	+1.34	−0.14	−0.84
ERCOT: residual load / clock time	$+7.21/-1.65$	$+7.92/+1.22$	$+6.81/+2.15$

Table F.1: Sensitivity of the whole-sector crossover $\theta^\star$. Both wedges are in whole-sector units, $B_V = w_G B_V^{\text{gen}}$ against B_K, with $w_G = 0.585$ unless the row says otherwise. The first block varies the assumed wind–solar composition of future deployment (Table F.2). The second is a reduced-form adaptation check: it attenuates the central cannibalisation slope by a quarter and by a half, asking what storage, transmission and demand response would have to deliver to defer the handoff, without modelling any of them. The third varies the generation share of sector gross output, which scales the whole output-value wedge one-for-one. Columns: the baseline logistic ceiling $\theta_{\max} = 0.90$; the $\theta_{\max} = 0.80$ robustness check; and a specification retaining only the $(1-v)\Delta\theta$ composition term of Equation (5), discarding the $-\theta\Delta v$ value-decline term, at the baseline ceiling. On the calibrated path the two channels of Equation (5) are of equal size by construction, because a linear schedule $v = v_0 - a\theta$ with $v_0 = 1$ implies $1 - \bar{v} = a\bar{\theta}$; the final column is therefore a halved wedge and a bounding specification, not an empirical decomposition. The third block spans the measured range of w_G documented in Table F.3. "> range" denotes a handoff deferred beyond the modelled penetration range.

		Full wedge		Composition channel
Sensitivity	Assumption	$\theta_{\max} = 0.90$	$\theta_{\max} = 0.80$	$\theta_{\max} = 0.90$
Central	$a = 1.30$, $w_G = 0.585$	0.40	0.42	0.63
Wind-heavy	EU 2024 mix, $a = 0.99$	0.52	> range	> range
Solar-heavy	60% solar, $a = 1.57$	0.33	0.35	0.52
Adaptation	a cut 25%: $a = 0.98$	0.53	> range	> range
Strong adaptation	a cut 50%: $a = 0.65$	> range	> range	> range
Low generation share	$a = 1.30$, $w_G = 0.52$	0.43	0.47	0.68
High generation share	$a = 1.30$, $w_G = 0.65$	0.37	0.38	0.60

Table F.2: Value-factor slopes used to calibrate the output-value bias. The technology-specific slopes a_j in $v_j(\theta_j) = v_0 - a_j\theta_j$ are the sum of the own-market and neighbouring-market coefficients from the cross-border spatial estimates of Stiewe et al. (2025), in percentage-point value-factor loss per percentage point of own-technology generation share. Mix blends apply $a_{\text{blend}} = \sum_j f_j^2 a_j$, with f_j the technology's share of wind-plus-solar generation; the Hirth (2013) blend is the central calibration and the Stiewe-based mixes define the band.

	Own-market	Neighbouring	Slope a_j
Wind	0.61	0.48	1.09
Solar	1.49	2.39	3.88
Blended calibrations (slope a)			
EU wind-heavy mix (2024)			0.99
60% solar mix			1.57
Hirth (2013) blend (central)			1.30

Table F.3: The generation weight w_G, measured. Each row is the generation share of electricity-sector output implied by one published decomposition. The two American estimators share a numerator and differ in the denominator: retail revenue in the first, BEA gross output for NAICS 2211 in the second. The European row excludes taxes and is an upper bound, since the energy-and-supply component includes the retail supply margin.

Estimator	Window	Mean	Min	Max
US, AEO price share: generation/(generation+T+D)	2012–2025	0.612	0.559	0.655
US, EIA generation revenue / BEA 2211 gross output	2012–2024	0.585	0.523	0.648
EU27, Eurostat energy-and-supply share, ex-tax	2017–2020	0.582	0.515	0.665
Maintained in the calibration		0.585	0.520	0.650

Sources: EIA, *Annual Energy Outlook*, Table 8, "Prices by Service Category", base year of vintages AEO2015 to the current release; BEA, Underlying GDP-by-Industry, gross output, NAICS 2211; Eurostat `nrg_pc_204_c` and `nrg_pc_205_c`, EU27, all consumption bands, components `NRG_SUP` and `NETC`.

Table G.1: Constructed renewable-capital exposure outside the United States, latest available vintage. Numerator: Ember wind and solar capacity at IRENA replacement cost with a perpetual-inventory net-stock adjustment. Denominator: Eurostat `nama_10_nfa_st`, NACE Section D, total fixed assets at current replacement cost.

System	Vintage	θ	$\widetilde{\omega}_R$	$\widetilde{\omega}_R/\theta$
Germany	2024	0.435	0.243	0.56
European Union	2023	0.270	0.178	0.66
Spain	2023	0.404	0.208	0.51
Denmark	2024	0.692	0.115	0.17

Notes: Eurostat NACE D is broader than electric power, offshore wind is not separately identified, and the ratios are sensitive to the valuation basis of the denominator. The table is a diagnostic, not an exposure measurement.

Table G.2: Matched 2010–2017 Section-D ranking under the US-anchored correction. This is a cross-country EU KLEMS diagnostic, not the paper's preferred US NAICS 2211 benchmark.

System	KLEMS TFP (%/yr)	$\bar{\theta}$	$\widetilde{\omega}_R/\theta$ (constructed)	B_K band (pp/yr)	Corrected TFP (%/yr)
Denmark	+1.15	0.406	0.58	2.31–4.61	−3.47 to −1.16
Netherlands	−0.17	0.071	1.71	0.37–0.74	−0.90 to −0.54
France	−0.59	0.043	6.49	0.20–0.40	−0.99 to −0.79
United States	−1.59	0.053	1.00 (measured)	0.26	−1.85
Germany	−1.31	0.160	4.74	0.74–1.47	−2.78 to −2.05
Italy	−3.19	0.123	1.73	0.68–1.36	−4.54 to −3.87
Finland	−2.22	0.027	2.34	0.15–0.30	−2.52 to −2.37

Notes: B_K bands apply the US-anchored $\widetilde{\omega}_R = \phi\theta$, $\phi \in [1, 2]$, not the constructed ratios in the fourth column, which are shown only to document their scatter. France's ratio of 6.49 is the clearest evidence that the raw construction is unreliable and is retained for that reason.

Table I.1: BEA source documents cited for the electric-power capital-deflator comparison.

Citation	Document	Used for
Bureau of Economic Analysis (2024b)	NIPA Handbook, Ch. 6 (Private Fixed Investment)	General PFI methodology
Bureau of Economic Analysis (2024c)	Updated Summary of NIPA Methodologies (Nov. 2024)	Deflation-methods table
McCulla et al. (2023)	Preview of 2023 Comprehensive Update (Jun. 2023)	Handy–Whitman → \$/kW switch, applied back to 2010
Mataloni and McCulla (2025)	2025 Annual Update (Nov. 2025)	Conventional line → Bureau of Reclamation, from 2024:Q1
Bureau of Economic Analysis (2026)	Table 5.4.4U data series (via DB-nomics)	Actual deflator numbers

Table I.2: BEA deflation of private fixed investment in electric-power structures.

Structure type	Price index, all years except most recent	Price index, most recent year
Alternative electric (wind and solar)	BEA weighted composite of EIA average annual construction costs for wind and solar generators, measured in dollars per kilowatt of installed nameplate (maximum) capacity (Bureau of Economic Analysis, 2024c)	
All other electric (conventional)	Weighted average of trade-source cost indexes for electric light-and-power plants and utility buildings (Handy–Whitman) (Whitman, Requardt and Associates, LLP, 2026; Bureau of Economic Analysis, 2024c)	Moving average of the Bureau of Reclamation composite construction-cost index (U.S. Bureau of Reclamation, 2026; Bureau of Economic Analysis, 2024c)

Note: The alternative-electric index was introduced in the 2023 comprehensive update and applied back to 2010 (McCulla et al., 2023). The source for the conventional line changed from Handy–Whitman to Bureau of Reclamation data beginning in 2024:Q1 (Mataloni and McCulla, 2025). These are separate changes: the first is the renewable-capital deflator studied in this paper; the second changes only the source used for other electric-power structures.