Powering the Energy Transition: Progress and Challenges*

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Abstract

The energy transition has advanced rapidly, but unevenly. The costs of wind, solar, and battery technologies have fallen sharply, driving record investments, while electrification of transport, heating, and industry continues to lag, weakening the revenues needed to sustain further clean investment. We review the Industrial Organization literature on the market-design questions raised by this mismatch. On the supply side, we discuss why long-term contracts are essential for financing clean assets and how their design and the auctions that allocate them shape efficiency and the scale of investments; investments in transmission, storage, and demand-response policies are also needed to help power systems accommodate intermittency across space and time. On the demand side, we examine why electrification remains sluggish despite declining clean-electricity costs. An overarching theme is the social acceptance and distributional consequences of the transition, as well as the policies designed to address them. Further research in this area could play an important role in informing ongoing policy design.

Keywords: Renewable Energy, Transmission, Energy Storage, Demand Response, Electrification, Distributional Effects.

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1 Introduction

The power sector is the backbone of the energy transition. Electricity can be generated from a diverse portfolio of primary sources, including wind and solar, whose costs have fallen so far and so fast that they are now the cheapest sources of new generation in much of the world. Decarbonizing electricity generation is therefore not only increasingly tractable, but also essential to decarbonizing the economy as a whole, since electrification is the main channel through which clean energy can reach transport, heating, and industry.

Progress has been remarkable, but it is still incomplete. The cost declines of the last decade have translated into record investment: renewable capacity additions have repeatedly broken records, while the growing deployment of solar, wind, and storage in combination suggests that intermittency —the drawback most commonly associated with renewables— may soon become less of a constraint. Yet this supply-side transformation has not been matched on the demand side: electrification of transport, heating, and industry continues to lag, and the resulting mismatch between abundant, cheap renewable supply and comparatively stagnant demand is beginning to depress the revenues that sustain further renewable investment.

Achieving the energy transition requires massive, and continued, investment — in renewables, transmission, storage, demand response, and electrification — and whether this investment materializes at the pace required depends on overcoming obstacles that are as much economic as they are technological: legacy market designs that lack sufficient long-term instruments to back the needed generation investments, grid bottlenecks and slow permitting, pricing structures that blunt incentives to electrify, and, increasingly, social and political resistance to the siting of the power plants and grids required to complete the transition.

This survey takes an Industrial Organization perspective on these challenges, building on, and complementing, a number of recent surveys of the economics of the energy transition (Fabra, 2021; Joskow, 2019; Kellogg and Reguant, 2021; Davis et al., 2024; Fabra and Reguant, 2024; Ito, 2026). Our focus is on the market-design and policy questions that determine whether private incentives align with the pace of decarbonization society requires: how renewable generators should be paid and exposed to risk, how intermittency should be absorbed across space and time, how the demand side should be brought along, and how the resulting costs and benefits are distributed.

Throughout the paper, we mainly focus on the experience in Europe and the United States, with some exceptions. Both provide valuable case studies for understanding the challenges of pushing the energy transition forward and offer several natural experiments to test ongoing policy initiatives. The energy transition is, of course, also taking place elsewhere, with challenges that are sometimes similar and sometimes markedly different; space and focus prevent this survey from covering the equally compelling issues that arise in developing countries.

The remainder of the survey is organized as follows. Section 2 documents the joint progress and frictions in renewable cost declines, investment, and electrification that motivate the rest of the paper. Section 3 examines how renewable generators are, and should be, paid: the case for long-term contracts, the frictions that limit greater contract liquidity, and the design of contracts and auctions to support renewable energy investments. Section 4 turns to how power systems cope with intermittency across space and time, through transmission, storage, and demand response. Section 5 examines the demand-side policies — covering transport, buildings, industry, and the recent surge in data-center demand — needed to accelerate electrification. Section 6 discusses the social acceptance and distributional consequences of the transition, and Section 7 concludes.

2 A Progress Report

Progress toward decarbonizing power has been markedly unbalanced. On the supply side, the last decade has delivered a technological revolution: the costs of wind, solar, and batteries have collapsed, and investment has followed suit. On the demand side, however, progress has been far more timid: electrification, the process through which cheap, clean electricity displaces fossil fuels in transport, heating, and industry, continues to lag well behind the required pace of decarbonization.

2.1 The Renewable Energy Revolution

The magnitude of the renewable energy cost decline is extraordinary: from being high-cost, immature technologies, solar and wind have become the cheapest sources of new electricity generation worldwide. Between 2010 and 2024, the global average installed cost of solar PV fell by 87%, to USD 708 per kilowatt (kW), while onshore wind costs fell by 55%, to USD 1,066/kW (IRENA, 2026a,c). In terms of the Levelized Cost of Electricity (*LCOE*), utility-scale solar and wind now cost, on average, USD 44/MWh and 33/MWh—already below the cheapest newly installed fossil-fuel alternative, at USD 50–100/MWh depending on gas prices (before even adding the social cost of carbon).

In parallel, battery storage (BESS) costs fell by 93%, to USD 197 per kilowatt-hour, reaching a new low in 2025. Arkolakis and Walsh (2024) quantify that this decline, combined with rapid solar and wind expansion, could reduce US electricity prices by 20% to 80% by 2040 relative to 2024.

As renewable penetration rises, the central economic challenge shifts from generating cheap electricity to delivering it reliably at the times and locations where it is valued: Joskow (2011) was among the first to argue that intermittent and dispatchable technologies cannot be compared on a simple *LCOE* basis, since the *value* of a unit of electricity depends on when it is produced. A recent industry benchmark, the *firm LCOE*, prices the additional storage and generation overbuild needed for co-located solar, wind, and batteries to deliver continuous, reliable supply, making costs across technologies more comparable. It too has declined, from above USD 100/MWh in 2020 to around USD 54–82/MWh by 2025 in high-irradiance and strong-wind regions.

Encouraged by, and partly endogenous to, these cost declines, investment in renewables has surged, with solar and wind now leading new investment in the power sector in many countries. Global renewable power capacity increased by a record 692 GW in 2025 alone, a 15.5% year-on-year increase, bringing cumulative installed capacity to 5,149 GW—though growth remains highly concentrated: Asia accounted for 74% of additions, with China alone contributing 440 GW, more than the rest of the world combined, while Europe (+77 GW) and North America (+42 GW) added considerably less (IRENA, 2026b). Hybrid solar-plus-storage investment is also becoming standard, with the paired share of new US utility-scale solar projected to become the majority of additions this decade.

Understanding the sources of these cost declines matters for policy. A substantial empirical literature attributes them to manufacturing economies of scale and learning-by-doing—costs fall predictably as cumulative deployment doubles—reinforced by public deployment policies (feed-in tariffs, auctions, tax credits) that pulled these technologies down their learning curves before they were commercially competitive on their own (e.g., Way et al., 2022; Kavlak et al., 2018). As Gerarden et al. (2026) emphasize, this makes the energy transition as much a story of industrial policy as of engineering: cost declines were largely policy-induced, and support-mechanism design shaped both the pace and cost of deployment.

2.2 Sluggish Electrification

The pace of renewable deployment has not been matched by a comparable pace of electrification. EU electricity demand grew by only 1% in 2025, after two prior years of decline, despite rising consumption from data centers, EVs, and heat pumps (IEA, 2026). Progress across end uses remains uneven: battery-electric vehicles rebounded strongly in 2025 but still accounted for only 17.4% of new EU car registrations (European Automobile Manufacturers' Association, 2026); European heat-pump sales fell by 22% in 2024 and, despite recovering in 2025, remain below the EU's deployment objectives (European Heat Pump Association, 2025, 2026); and industrial electrification has advanced particularly slowly (IEA, 2026; Rosenow et al., 2025).

A similar gap is evident in the United States. Electricity demand grew by approximately 1.7% per year between 2020 and 2025, following nearly two decades of stagnation, but much of this acceleration reflects data centers and other large commercial and industrial loads rather than broad-based end-use electrification (U.S. Energy Information Administration, 2026). Electric vehicles accounted for only slightly more than 10% of new car sales in 2024, constrained by vehicle costs, charging infrastructure, and substantial geographic and political heterogeneity (IEA, 2025; Archsmith et al., 2022; Gillingham et al., 2023; Davis et al., 2025), while heat pumps remain the primary heating technology in only about 14% of U.S. households (Davis, 2024). In sum, despite the recent recovery in demand growth and rapidly decarbonizing generation, electrification of transport, buildings, and industry in both Europe and the United States remains incomplete.

As further documented in SEction 5, several factors explain this sluggishness (Section 5): insufficient grid infrastructure, uncertainty over suitable technologies, slow permitting, high capital costs, and, arguably most importantly, electricity prices that remain high and volatile. Borenstein and Bushnell (2022) show that the wedge between retail prices and marginal generation costs systematically discourages electrification relative to fossil-fuel substitutes, even where electrification would be socially efficient.

2.3 The Mismatch between Demand and Supply

The combination of rapid renewable deployment and slow electrification gives rise to another symptom: the so-called cannibalization effect, studied empirically by Gowrisankaran et al. (2016), theoretically by Acemoglu et al. (2017), and emphasized from a policy perspective by Fabra (2023) and Joskow (2019). As renewable capacity expands, the supply curve shifts outward; *ceteris paribus*, this depresses prices precisely when renewables are generating, lowering the average price renewable generators receive relative to the market-wide average. When the supply shift is strong enough, excess supply can arise, leading to curtailment and negative prices. This persists even when generators bid strategically: markups over their near-zero marginal costs gradually decline as renewable capacity increases (Fabra and Llobet, 2023), and may reshape market structure by encouraging firms to separate ownership of renewable and thermal assets to soften competition (Fabra and Llobet, 2026b).

In sum, renewable producers face not only low and uncertain prices, but also quantity risk from curtailment, over and above the resource's inherent variability. The consequence is low profitability and high risk for renewable investments: in Joskow (2019)'s words, *"this "revenue inadequacy" or "missing money" problem can lead to premature exit of existing capacity as well as inadequate investment in new capacity"*.

Curtailment has (at least) three distinct causes, with different policy implications. The first is the supply-demand imbalance just discussed: renewable output can exceed demand at a system level, regardless of grid capacity. The second is a grid problem: renewables are curtailed in some locations while nearby areas that could absorb the excess supply lack the transmission capacity to do so (Section 4.1); Petersen et al. (2024) and Brown and Reguant (2026) document that the resulting congestion and reliability costs rise with renewable penetration, though less than the benefits achieved. The third is the limited flexibility of the existing generation fleet and the scarcity of storage and demand response able to absorb electricity when abundant and release it when scarce (Sections 4.2 and 4.3). The result is not simply a demand-supply gap but a mismatch between the *type* of demand and the *type* of supply the system has.

Left unaddressed, this mismatch risks a vicious circle: without investment in electrification, demand stagnates; returns to renewable investment fall, deployment slows, and electricity remains expensive and volatile precisely when low, stable prices are what would encourage electrification in the first place. This coordination failure between two margins that should advance together—investment in low-carbon generation and in electrification—has a common root: the absence of sufficient long-term contracting. Generators lack the revenue certainty needed to finance new investment, while consumers and households lack predictable, affordable prices against which to commit to electrifying production processes, vehicles, boilers, and furnaces.

3 Investing in Renewable Energies

3.1 The Missing Link: Long-Term Contracts

There is broad agreement that long-term contracting is essential to support investment in low-carbon generation. By stabilizing the revenues received by renewable producers, these contracts shield investors from wholesale-price volatility and from the cannibalization effect described above, thereby restoring incentives that reliance on spot-market revenues alone would weaken (Fabra and Llobet, 2026a). Regulators likewise view long-term agreements between buyers and sellers as a means of reducing risk and encouraging investment in renewable generation. As the European Commission stated in its electricity-market reform, *"the ultimate objective is to provide secure, stable investment conditions for renewable and low-carbon energy developers by bringing down risk and capital costs while avoiding windfall profits in periods of high prices"* (Council of the European Union, 2024). In the same vein, the World Bank has emphasized that long-term power contracts are *"central to the private sector participant's ability to raise finance for the project, recover its capital costs, and earn a return on equity"* (World Bank, 2024).

Indeed, as those quotes emphasize, contracts matter beyond smoothing revenue risk: they shape the cost and availability of capital itself. Darmouni et al. (2026) show that renewable and fossil generation, despite producing an identical output, are financed very differently, with renewables relying heavily on project finance backed by some form of fixed-price contracts, either private Power Purchase Agreements (PPAs) or publicly-backed Contracts for Differences (CfDs). By converting an uncertain revenue stream into a certain one, fixed-price contracts reduce cash-flow risk sufficiently to let developers substitute cheaper bank debt for costlier equity, lowering the overall cost of capital. May and Neuhoff (2021) reach a complementary conclusion: the design of the underlying support policy, and the regulatory and price risk it leaves with investors or off-takers, can shift financing costs for wind power by 30% of project value.[1]

However, a puzzle remains: if both buyers and sellers would benefit from long-term contracts, why is there not enough contract liquidity? And for that reason, why do governments so often feel compelled to intervene to facilitate long-term contracting, whether through CfD auctions, or credit guarantees? Part of the answer lies on the buyer's side. Large, risk-averse consumers operating in competitive product markets are often unwilling to sign long-term, fixed-price power purchase agreements: if wholesale prices later fall, a buyer locked into a fixed price could find itself paying more than its rivals, particularly over horizons that exceed its own business-planning cycle (Fabra and Llobet, 2026a). This asymmetry is compounded for offshore wind and other large-scale projects, whose long construction lead times often require locking in prices years in advance and finding off-takers large enough to absorb their entire output, raising transaction costs. Exposure to future input price inflation could also be a reason for the observed low realization rates of some renewable energy projects awarded through auctions (Matthäus, 2020).

A second, and arguably more fundamental, part of the answer concerns counterparty risk. Using a theoretical model, Fabra and Llobet (2026a) show that the mere possibility that buyers may seek to renegotiate a contract when spot prices fall below the agreed price is sufficient to raise equilibrium contract prices. Higher contract prices, in turn, make renegotiation more likely, reducing the expected profitability of investment under long-term contracts and limiting the scale of investment that can be profitably undertaken. Using simulations calibrated to the Spanish solar market, this paper also evaluates the effects of public guarantees, subsidies, and collateral requirements as possible remedies. Although these instruments can partially restore market liquidity, they entail their own trade-offs, including moral hazard and reliance on costly public funds.

Empirically, Ryan (2025) documents a closely related hold-up problem in the Indian solar

[1] See also Gohdes et al. (2022) and Dukan and Kitzing (2023) for additional evidence on the role of long-term contracts in facilitating financing of renewable projects.

market, where ex post renegotiation by buyers weakens the credibility of long-term contracts awarded through auctions, raises equilibrium contract prices, and depresses investment. As Fabra and Llobet (2025) also emphasize, imperfect contract enforcement is a central reason why long-term contracting for renewable generation requires careful public design—and often public backing—rather than being left entirely to private counterparties. Auctions of publicly-backed contracts provide a complementary policy response, but their design has to be carefully studied as it affects both procurement costs and the efficient operation of the resulting assets, an issue to which we turn next.

3.2 Contract and Auction Design for Renewables

If the case for allocating long-term contracts through auctions is established, a further question arises: how should these contracts and auctions be designed? Despite their widespread use in renewable-energy procurement worldwide, rigorous empirical evidence on the effects of specific design features remains limited, in part because no two auctions are the same. Cross-country comparisons are further complicated by differences in market conditions, institutions, and policy environments. Anatolitis et al. (2022) provide one of the few comprehensive empirical studies of this issue, exploiting variation in auction design across European countries between 2012 and 2020. Their findings point to one overarching conclusion: the heterogeneity of outcomes cautions against one-size-fits-all prescriptions. Contract and auction design should instead be tailored to the characteristics and needs of the market in which investment is expected to occur (Fabra, 2023).

Nevertheless, the existing literature offers several useful lessons, which we organize around two broad sets of choices: the design of the underlying contract and the rules governing the auction—two issues that, as Cantillon and Spagnolo (2026) note, are fundamentally interlinked. These choices determine whether the most efficient projects are selected at the lowest cost to consumers, and whether the resulting plants are operated and maintained efficiently once built.

Pay for capacity or for output? A first contract design choice is whether renewable generators should be paid for the capacity they install or for the electricity they actually deliver. Aldy et al. (2023) exploit a natural experiment in which US wind developers could choose between an investment (capacity-based) payment and a production (output-based) payment. They find that claimants of capacity-based schemes produce 10–12% less electricity than they would have produced under an output-based scheme. A potential explanation is that the former induce weaker incentives to maintain the plants efficiently, thus reducing the plants' output.

From a different, contract-design perspective, Fabra and Llobet (2025) also favor output-based payments in contexts where adverse selection is important—e.g., if projects differ in expected production because of variation in resource quality, yet they all need to be offered the same contract because of information asymmetries or institutional constraints. In such contexts, tying remuneration to output is optimal as it helps direct investment toward locations with better wind or solar resources. The prescription is reversed, however, when adverse selection is absent—e.g., when the regulator observes and can contract on expected production—but moral hazard is relevant—e.g., as when firms undertake costly, unobservable actions to reduce costs (effort) or shift generation toward high-price periods. In such settings, output-based remuneration exposes investors to greater revenue uncertainty. If they are risk-averse, this creates an extra cost and weakens their incentives to exert effort—a disincentive that can be mitigated by paying them on the basis of expected rather than realized production.

An additional, distinct reason given for not using output-based schemes is that it leads renewable generators to keep producing even when prices turn negative (Matthäus, 2020; Ambec et al., 2025), an issue that can nevertheless be avoided by setting price floors at zero, below which the plant would be fully exposed to market prices. In the UK market, where offshore wind is supported through Contracts for Difference, Steenberghe and Ovaere (2026) find that CfD-backed wind farms curtailed output similarly to merchant generators only once

CfD payments were suspended following six or more consecutive hours of negative prices. The guidance given by the European Commission (2025) is to pay producers according to what they *could* have produced when prices turn negative. This mitigates quantity risk without distorting production decisions, but weakens incentives to locate projects where curtailment risk is lower.

How much price exposure to spot prices? A second, closely related contract design choice is how much of the wholesale-price risk the contract should pass through to the generator. Full exposure to spot prices sharpens generators' incentives to produce at the times and locations where electricity is most valuable, but, as discussed above, it also exposes their revenues to cannibalization and volatility, raising financing costs. Shielding generators from spot prices through fixed-price contracts does the opposite: it stabilizes revenues but weakens these locational and operational incentives.[2] As a consequence, in the moral-hazard setting of Fabra and Llobet (2025) described above, the optimal contract has partial price exposure to strike a balance between the de-risking and the efficiency incentives. Fabra and Llobet (2026c) push it further by asking how price exposure should optimally be allocated *across* bidders of heterogeneous quality within a single auction — a question to which we turn next.

Price-only auctions or scoring auctions? Most renewable auctions select winners on price alone. Yet, price is not necessarily a sufficient statistic for the value of a project, particularly once that value depends on which technology is chosen, and when and where it generates. Crucially, this is not merely a problem for comparing different technologies (e.g., wind versus solar); as Callaway et al. (2018) show, projects using the *same* technology can differ substantially in value once location is taken into account.

[2] Fabra and Imelda (2023) provide causal evidence of a distinct effect, exploiting a Spanish policy change that shifted renewable generators between full price exposure and fixed prices: reducing price exposure lowered the price-cost markups charged by dominant incumbent firms by 2–4%, precisely because it removed their incentive to withhold output when doing so would raise the price received by their own renewable capacity.

To illustrate this, consider two wind farms with the same expected output. One is situated in an area where wind generation is concentrated in the late afternoon, when electricity demand is high and solar output is low. Its production therefore replaces costly, emissions-intensive peaking generation. The other is located where wind generation occurs mainly during daylight hours, when it competes with inexpensive, zero-carbon solar power. Even though the two projects are technologically comparable, the first creates greater system value because it avoids more operating costs and emissions. Competition for a fixed-price contract would favor the project that is less costly to develop, even though it may not be the one that creates the greatest system value. Yet, if the auctioneer cannot directly observe which project is more valuable, how can the auction be designed to reward both cost efficiency and value?

To shed light on this question, Fabra and Llobet (2026c) study the design of procurement contracts when the value of the procured good—renewable power—is reflected in future market prices, but is non-contractible at the investment stage as it is still unknown. A contract that combines a fixed price set at the auction with some degree of price exposure improves selection by allowing high-value investors to benefit more from aggressive bidding, as they will increase the chances of winning while compensating the lower auction price with greater spot-market revenues. However, as already discussed, such price exposure is costly whenever price risk cannot be fully hedged. Hence, it is optimal to offer contracts with lower price exposure for lower-value investors, allowing high-value investors to signal their type by taking on more risk. Furthermore, using a score to tilt the allocation in favor of higher-value projects — rather than using the price offers alone — becomes essential to achieving any selection on value at all.

This result offers a rationale for scoring auctions—beyond simply rewarding non-price attributes such as local content or emissions—when the value of a project is reflected in electricity market prices: a score can serve as a substitute for price exposure as a screening device without exposing investors to costly risk.[3]

Pay-as-bid or uniform-price format? A further, more classical auction design choice is whether winning bidders are paid their own bid (pay-as-bid) or the highest accepted bid (uniform price). While this question has long divided auction theorists and practitioners in electricity markets (Fabra et al., 2006), a key lesson emerges: uniform price auctions can encourage truthful bidding but leave more rents to low-cost bidders as compared to pay-as-bid auctions. Furthermore, uniform price auctions can facilitate collusion (Fabra, 2003). These main lessons should broadly carry over to renewable energy auctions, but whether they extend to when bidders differ, not only in their costs, but also in their value —i.e., the timing and location of the electricity they can deliver— is, to our knowledge, still largely unexplored.

Technology-neutral or technology-specific support? Another important auction design choice is whether to run a single technology-neutral auction across all renewable technologies or separate technology-specific auctions. Fabra and Montero (2022) study how an imperfectly informed regulator should optimally procure a good, such as clean energy, that can be produced with heterogeneous technologies at different costs, comparing technology-specific auctions, technology-neutral auctions, and intermediate options such as technology banding. They show that no single instrument dominates: the best choice depends on the extent of cost heterogeneity across technologies, the severity of the regulator's informational disadvantage, the shadow cost of public funds, and the degree of market power among bidders. Using Spanish data, they find that well-designed technology-specific auctions can outperform both technology-neutral auctions and technology banding, cautioning against a default preference for technology neutrality on efficiency grounds alone.

[3] From a practical point of view, the European Commission (2024) provides guidance on auction design to reward such non-price attributes in renewable energy auctions.

Prequalification requirements. Auctions typically also impose prequalification requirements — financial guarantees, development milestones, or minimum track records — intended to screen out bidders unlikely to deliver on their contracts. These requirements interact directly with the counterparty-risk and financing frictions discussed above, and affect the intensity of competition: tighter prequalification can improve delivery rates but risks excluding smaller or newer developers who might otherwise offer competitive costs. Relative to the price exposure and technology dimensions discussed above, the study of the suitability and design of prequalification requirements remains comparatively underexplored.

Two increasingly important questions also remain largely unresolved in the literature, to the best of our knowledge.

Baseload or pay-as-produced? First, should contracts take a baseload form, requiring delivery of a fixed quantity of electricity, or a pay-as-produced form, under which remuneration is tied to the intermittent output actually generated? Baseload contracts may be better aligned with the buyer's consumption profile, but they expose producers to market-price and quantity risks whenever their plants are unable to meet the contracted volume.

Hedging curtailment? Second, should generators be compensated for curtailed output and, if so, how should such compensation be structured? Full or partial compensation reduces investors' exposure to quantity risk, but it also weakens their incentives to choose locations and technologies that are less vulnerable to curtailment, including the decision to co-locate generation with storage or with technologies whose availability is negatively correlated in ways that reduce spills.[4]

Both questions reflect the broader trade-off between de-risking investment and preserving incentives for efficient investment decisions, including the choice of technology and project

[4]See Klinge Jacobsen and Schröder (2012) for a policy discussion. Lopez Garcia et al. (2026) conduct a large-scale natural field experiment in which consumers are incentivized to increase demand at locations and times when renewable generation would otherwise be curtailed. They find the policy effective in stimulating demand, reducing curtailment, and generating welfare gains that would otherwise be lost.

location. Existing analyses of market exposure implicitly address how much *price* risk generators should bear, but offer comparatively little guidance on how contracts should allocate *quantity* risk. Importantly, this risk arises from both weather-dependent generation, and endogenous investment and operational decisions, which are themselves shaped by contract design.

4 Coping with Intermittency

A power system with large-scale wind and solar deployment needs flexible resources capable of absorbing intermittency across space and time. As electrification raises overall demand, whether this strains the system depends on whether that additional demand materializes when and where supply is abundant, or whether there is enough supply-side and demand-side flexibility to absorb the mismatch— an issue that has become particularly salient in the policy debate about data centers' impact (Knittel et al., 2025).

Transmission, storage, and demand response can provide such flexibility as each can, up to a point, close the gap between variable supply and demand. Yet none is sufficient on its own, and none is perfect in isolation. Transmission and storage both require costly, lumpy investments, and their value depends on locational and temporal price differences, revealed only if wholesale prices are granular enough to signal where and when constraints bind. Demand response requires comparatively little investment, but its scope is inherently limited: only a fraction of demand can be shifted, and by how much depends on behavioral, informational, and contractual frictions. Because these three margins are imperfect substitutes rather than perfect ones, investments in transmission, storage, and demand-side flexibility have to be coordinated jointly. The following three subsections discuss each in turn.

4.1 Transmission and Market Integration

The gains from electricity market integration are substantial and well documented: interconnecting previously separate markets reduces generation costs, mitigates local market power, strengthens security of supply, allows to better integrate renewable resources, and shields consumers from local shocks. De Cannière (2026) exploits exogenous variation in Belgium's available cross-border transmission capacity—driven by loop flows from German wind generation—to estimate the effects of market integration on productive efficiency. She finds that, when transmission constraints bind, domestic production costs increase by 34% as domestic firms, shielded from foreign competition, exercise greater market power. At the same time, the realized gains from trade fall by 83%. Relatedly, in the US context, Cicala (2022) shows that market-based dispatch across regions, relative to fragmented regulatory coordination, generates sizable cost savings.

These integration benefits are especially valuable in power systems with a large share of renewables. The best wind and solar resources are rarely located near existing demand centers or near the legacy fleet of thermal plants, whose siting instead reflected access to fuel transport, cooling water, and proximity to load (Joskow, 2021). Unlike fossil fuels, wind and sunlight cannot be shipped, so plants must locate where the resource itself is found; the electricity they produce must instead be moved to where it is consumed, requiring transmission capacity on a scale well beyond what the legacy grid was built to accommodate (Davis et al., 2024). Pooling wind and solar output over a wider geographic area also smooths their combined variability, so that the economic value of a given unit of renewable capacity rises with the size of the market it can reach (Hausman, 2025).

Market integration therefore delivers the static gains from trade documented above, and it also shapes investment incentives in renewable capacity itself, along at least three margins. First, transmission affects renewable entry directly. Gonzales et al. (2023) study the effects of two new transmission lines that connected Chile's renewable-intensive Atacama region to two separate demand centers — the nearby mining industry around Antofagasta, linked in 2017, and the country's main population center, Santiago, several hundred kilometers to the south, linked in 2019. They show that the resulting market integration increased solar generation by around 180% (reflecting, in part, entry that would not have occurred absent the anticipated interconnection), lowered generation costs by 8%, and reduced carbon emissions by 5%.

Second, and distinctly, transmission matters well before any line is ever congested, through the interconnection process itself: as in many other jurisdictions, Johnston et al. (2023) document a long and growing backlog of interconnection requests in the US, with each additional request imposing a congestion externality on others already in the queue by lengthening, and adding uncertainty to, their own waiting times. Because the cost of joining the queue is low relative to this externality, the queue itself becomes a further obstacle to renewable deployment, one that additional transmission capacity can help relieve. Likewise, as studied by Johnston et al. (2023) through counterfactual exercises, there is scope to reduce the waiting times through more efficient queuing mechanisms.

Third, better-integrated grids affect the exit margin: incumbent fossil generators facing renewable entry have historically been partially shielded from the resulting decline in wholesale prices by the very transmission constraints that segment them from the fastest-growing renewable regions. Hence, the grid expansion, by exposing incumbents to renewable competition, can also hasten their retirement (Bushnell and Novan, 2021).

Taken together, these entry and exit margins imply that conventional cost-benefit assessments of transmission projects, which typically hold the generation fleet fixed, are likely to substantially understate the benefits of grid expansion for the pace of the energy transition.

There is a further, related channel through which transmission investment matters: market power. When the grid is congested, generators serving the thinner, disconnected markets can raise prices above competitive levels, as highlighted in the seminal works of Joskow and Tirole (2000) and Borenstein et al. (2000), and documented empirically by several others since. Wolak (2003) documents this in Alberta, where transmission expansion caused incumbent suppliers to bid closer to marginal cost and market-clearing prices to fall closer to competitive benchmarks. Davis and Hausman (2016) find that the 2012 closure of a nuclear plant in California created new transmission constraints that raised costs and opened room for the exercise of local market power. And, Ryan (2021) quantifies these effects in the Indian context, where firms were found to raise their bids by roughly 8% of the mean bid price during congested hours relative to uncongested ones. As a consequence, transmission expansion could lower firms' optimal bids by around 20% of marginal cost during those hours, raising total market surplus by 22%, one third of which comes specifically from sellers' more competitive response to a better-integrated grid. This amount would be large enough on its own to justify the underlying transmission investment.

In sum, there is broad consensus on the benefits of transmission expansion, which exceed what traditional assessments capture both through improved allocative efficiency (lower dispatch costs and mitigated market power) and improved dynamic efficiency (sharper entry and exit incentives). Yet the pace of transmission build-out has persistently lagged what this consensus would recommend. Part of the explanation lies in familiar frictions — lengthy legal and permitting processes, and local opposition to new lines, as we further discuss in Section 6 — but part of it is more directly economic. As documented by Hausman (2025) with US evidence, incumbent generators who benefit from segmented markets, and whose profits fall precisely when new transmission lets in cheaper renewable competition and lower prices, have both the incentive and often the standing to delay or block the lines that would erode their revenues. As renewable penetration continues to rise, these incentives to obstruct transmission expansion are, if anything, likely to strengthen rather than fade.

4.2 Energy Storage

The allocative and dynamic efficiency gains discussed for transmission in the previous section carry over to storage, albeit with a slight reinterpretation. While transmission counteracts the geographic mismatch between renewable availability and demand, storage counteracts it across time. Transmission is thus most valuable when price differences across interconnected systems are large, and prices at both sides of the border are weakly or negatively correlated via their demand and renewable energy shocks. Likewise, storage is most valuable where *intertemporal* price spreads are large, and subject to weakly or negatively correlated shocks across time.

As renewable penetration rises, within-day price swings tend to widen: prices fall —sometimes even below zero— when renewable output is abundant, and spike when it is scarce and gas-fired plants ramp up to meet demand. Batteries that charge when prices are low and discharge when they are high smooth out these swings, containing production costs and emissions by displacing thermal generation with renewable output, and reducing the need to invest in costly back-up capacity. To the extent that batteries are not owned by dominant thermal incumbents, they also mitigate market power by becoming a competing source of supply when they discharge (Andrés-Cerezo and Fabra, 2023).

The resulting price patterns, and hence the value and profitability of storage, are shaped by the underlying technology mix. Andrés-Cerezo and Fabra (2026) study this issue by modeling the interaction of renewable energies and storage under different technology mixes. For instance, in markets with abundant solar, prices trace the so-called *duck curve*, with a belly of low midday prices and a long evening neck when gas becomes price-setting. This pattern makes solar and storage highly complementary: storage arbitrages the large belly-to-neck spreads, pushing prices up when solar produces relatively more, while also curbing midday solar curtailment. This partly comes at wind's expense, since discharging depresses prices at night, when wind is relatively more available. The authors also simulate the Spanish market and, in line with the theoretical predictions, show that raising storage from 4 to 40 GWh under a high-renewables scenario (82% wind and solar, as projected for 2030) raises solar's captured prices by 16% while lowering wind's by 14%. For storage, the deployment of renewables allows their arbitrage profits and capacity utilization rates to rise tenfold relative to a 43% renewables scenario. As more storage is deployed, however, a cannibalization effect sets in: prices across hours converge, eroding the arbitrage margins that justify further storage investment. The complementarity between abundant solar and storage suggests that storage subsidies can be phased down as both investments rise together.[5]

Using data from California, Butters et al. (2025) document both the complementarity between solar generation and storage and the cannibalization effects that emerge as storage deployment expands. First, they show that, absent subsidies, the first unit of storage becomes profitable only once the renewable share reaches roughly 50%. Second, as the battery fleet expands, storage operation compresses intraday price variation, reducing the arbitrage opportunities on which storage revenues depend. As a result, arbitrage profits alone are insufficient to support battery fleets of 10 GWh or more, implying that such deployment would require either continued subsidies or capital costs below current expectations.

The parallels between transmission and storage are well understood, yet they are not fully reflected in public policy. While unbundling rules require transmission owners to remain independent of generation in order to limit foreclosure and self-serving network planning, no comparable restrictions apply to storage. This asymmetry is potentially consequential. Andrés-Cerezo and Fabra (2023) show that vertical integration between dominant generators and storage can distort storage operation, since discharging lowers the electricity prices received by the firm's own generation assets. As a result, vertically integrated firms underuse and underinvest in storage, leading to worse outcomes for consumers and total welfare than under independent storage ownership—even when the storage operator itself has market power. The first-best outcome—or the second-best when the electricity market is subject to market power—is achieved when an independent actor, such as the system operator, determines storage investment and operation so as to minimize total system costs.

This concern does not arise when neither party has market power. In particular, Andrés-Cerezo and Fabra (2026) show that co-locating renewables and batteries —often owned by

[5] Yet Andrés-Cerezo and Fabra (2026) also show that when solar penetration remains low and midday prices are still relatively high, solar and storage can become strategic substitutes. Storage tends to charge when solar output is low and discharge when it is high, thereby reducing the prices captured by solar generators.

the same firms— can be efficient when it helps relieve transmission constraints. In congested areas, integrated renewable-storage operators systematically charge when renewable output is abundant and discharge when it is scarce, reinforcing the economic complementarity between the two technologies and strengthening incentives to invest in both.

Nevertheless, storage is not homogeneous. Short-duration batteries can arbitrage intra-day price differences, but multi-day and seasonal scarcity require different technologies and remuneration mechanisms. Prolonged *Dunkelflaute* episodes and heat waves are particularly challenging, as short-duration storage, demand response, and even cross-border transmission may be insufficient when scarcity persists across regions (Beck-Bang et al., 2026). Addressing these longer-duration imbalances remains an important area for research.

4.3 Demand Response

Demand response is the demand-side analog of storage. Instead of moving electricity across time physically, it moves the services that electricity provides: cooling a room earlier, heating water before a price peak, charging an electric vehicle when solar output is abundant, or postponing electricity consumption when it is scarce. In a system dominated by dispatchable fossil generation, this margin was useful mainly for reducing peak capacity needs and mitigating market power in scarcity hours. In a system dominated by wind and solar, it becomes even more valuable, because marginal costs vary sharply with demand and weather.

But for demand response to materialize, consumers must face prices that reflect the time-varying marginal cost of supplying electricity. Yet under commonly used time-invariant prices, consumers face prices that are too low in high-cost hours and too high in low-cost hours, so they consume too much when clean electricity is scarce and too little when it is abundant. Borenstein and Holland (2005) show that this distortion generates welfare losses even in otherwise competitive electricity markets, and that those losses rise with wholesale price volatility and consumers' ability to substitute across hours. The same logic is amplified by renewable penetration. In high-renewable systems, real-time prices can reduce the cost of integrating clean power by shifting demand toward low-cost hours and away from scarcity hours (Imelda et al., 2024). Reassessing time-varying rates using all seven US wholesale markets, Hinchberger et al. (2024) find that simple time-of-use and critical-peak tariffs each capture only about 10% of the potential reduction in mispricing, while real-time pricing with price caps can capture most gains while limiting bill risk.

The policy difficulty is that theoretical demand response is much larger than the manual response typically observed in the field. One reason is attention. Consumers see bills infrequently, do not know the load of individual appliances, and may rationally ignore small and changing price differences. Ito (2014) shows that households respond to average rather than marginal prices under nonlinear tariffs, and Jessoe and Rapson (2014) finds that information provision can increase price responsiveness when households otherwise have little real-time feedback. First-generation pricing experiments are also hard to interpret as estimates of short-run elasticities, since many randomized interventions varied information or technology access rather than real-time prices themselves (Bollinger and Hartmann, 2020). The Spanish experience points in the same direction: despite exposure to hourly wholesale prices, Fabra et al. (2021) estimate zero average short-run elasticities, suggesting that price variation alone is not enough when attention and adjustment costs remain high.[6] Without automation, predetermined time-of-use tariffs may sometimes work better than real-time pricing, as they make the relevant price variation more salient and predictable (Enrich et al., 2024). However, these administratively fixed periods can be misaligned with flexibility needs.

This initial evidence suggests that demand response is not a generic property of electricity consumption and that, without further intervention, it remains relatively low even in the most incentivized experiments. Recent evidence, however, is more optimistic about the flexible loads created by electrification. Electric vehicles are particularly important because they add large, potentially deferrable loads. Bailey et al. (2025b) use a field experiment to

[6] Such zero short-run elasticities were estimated for the period 2016–2017, when prices and within-day price variation were relatively low, raising the possibility that weak price signals explained the null response. However, Fabra et al. (2026c) re-estimate demand elasticities for 2021–2023, when the energy crisis brought much higher and more volatile prices, and again find a short-run elasticity close to zero.

show that EV owners respond strongly to financial incentives to shift charging, while a prosocial nudge has no detectable effect and behavior reverts when incentives are removed. But Bailey et al. (2025a) show that tariff design matters: standard time-of-use prices can synchronize many households into a new off-peak "shadow peak," increasing local distribution constraints. Centrally managed charging avoids this coordination failure and is well tolerated by consumers. Complementary evidence from Australia shows that incentives can also increase midday charging during solar hours, but the response depends on parking location and access to workplace or public chargers (La Nauze et al., 2026).

Automation appears to be the second key ingredient. Bollinger and Hartmann (2020) find that automation, rather than information alone, generates the short-run elasticity needed to justify real-time pricing. Notably, Metcalfe et al. (2026) find a strong demand response for EV charging in a large-scale UK field experiment: an AI-managed tariff reduced household electricity demand during peak hours by 42%, with the displaced consumption shifted entirely to lower-cost, lower-carbon periods. Similarly, Blonz et al. (2025) show that smart thermostats can automate response to time-varying prices, reducing air-conditioning consumption during expensive afternoon periods with limited overrides. In a 17-month experiment with individually randomized peak events, Bailey et al. (2025c) compare households facing manual response, app-enabled control, and utility-managed control of thermostats, water heaters, and EV chargers. The centrally managed group reduced event consumption by 26.3%, compared with about 5% under both app-enabled and manual response; making response passive mattered much more than simply giving households smart controls. The conclusion is not that households are unwilling to be flexible, but that flexibility is much more valuable when the adjustment burden is removed and comfort or mobility constraints are respected.

Large-scale programs reinforce this message. The UK's Demand Flexibility Service, evaluated using Octopus Energy data, induced substantial reductions during peak events, with stronger responses among households owning low-carbon technologies such as EVs, heat pumps, solar, and batteries (Bernard et al., 2026). Conversely, experiments by the Centre for Net Zero and Octopus in Great Britain and Spain show that households can also be induced to increase consumption during periods of renewable abundance; the response is largest for households with low-carbon technologies and time-of-use tariffs, and free electricity appears more cost-effective than paying customers to consume beyond a zero price (Lopez Garcia et al., 2026).

Taken together, the evidence suggests a more nuanced role for demand response. It is unlikely to solve intermittency through broad, manual household responsiveness to prices. But it can become a meaningful source of flexibility as electrification expands controllable loads, and as retailers or aggregators coordinate those loads through contracts that respect consumers' preferences. This makes demand response less a stand-alone substitute for storage and transmission than a complementary tool when well-designed market prices can interact with automation and flexibility programs.

5 Demand-Side Policies: Electrification

In addition to a massive transformation of the supply side of electricity generation, massive investments will be required over the coming years in the residential and industrial sectors, as households and firms switch from fossil fuels to electricity. This makes electrification the demand-side mirror image of the investment problem discussed in Section 3. Renewable developers need credible revenues to invest; households and firms need predictable, and sufficiently low electricity costs to justify replacing cars, boilers, furnaces, and industrial equipment before the end of their useful lives. When retail electricity prices are high relative to gas, gasoline, or diesel, or when future electricity prices are volatile and difficult to hedge, clean electricity can fail to displace fossil fuels even when generation itself is increasingly low-carbon. As Figure 1 shows, economy-wide electrification has increased only gradually in many regions since 2000, with faster growth in China, Japan, and Korea than in the

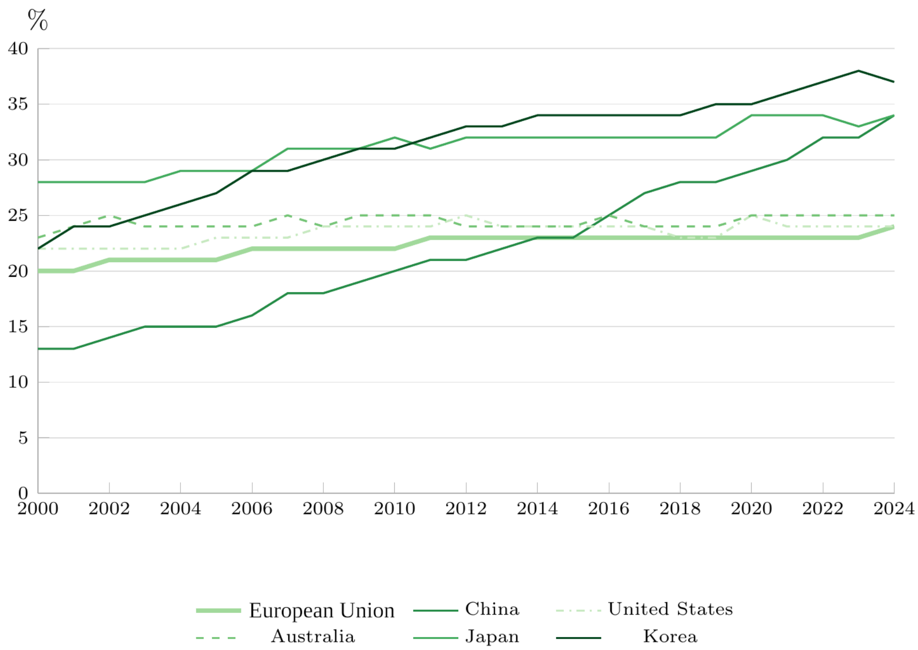

Figure 1: **Economy-wide electrification rate in selected regions, 2000–2024**

Notes: This figure shows the evolution of electrification of final energy consumption across regions, from 2000 until 2024. Source: International Energy Agency (2026).

European Union or the United States.

Successful electrification policies need to align the full set of incentives. Electrification raises electricity demand, and thus can make the energy transition harder to accomplish. However, there are potential complementarities with adequate incentives and programs. An electric vehicle charged during solar-abundant hours can absorb low-cost renewable output, while the same vehicle charged at the evening peak can aggravate capacity and distribution constraints. A heat pump lowers emissions most when it replaces fossil heating in a clean grid, but it may increase winter peak demand unless paired with efficient buildings, thermal storage, or flexible tariffs. Industrial electrification is even more sensitive to electricity prices, because energy costs are a large share of operating costs in some sectors. Across these settings, electrification policy has to combine adoption incentives, infrastructure investment, retail-rate reform, and, increasingly, long-term contracting for clean electricity.

5.1 Electrifying Transport

Transport is the most visible frontier of electrification. Electric vehicles have improved rapidly and often entail lower operating costs than internal-combustion vehicles, yet adoption remains constrained by high upfront costs, range anxiety, limited charging access, and heterogeneous preferences over vehicle attributes. Barahona et al. (2026) show that these frictions help explain the limited shift toward EVs following the introduction of Madrid's Low Emission Zone, restricting access to polluting vehicles in much of the city centre. EV new registrations increased by only 0.14 per 10,000 residents, compared with 1.42 for hybrids, suggesting that consumers still favor technologies that mitigate concerns over range and charging availability. Other urban policies, such as promoting EV car sharing, may be more effective in shifting users toward cleaner mobility. Muehlegger et al. (2026) show, also for Madrid, that expanding EV car sharing draws users away from public transport and private driving in roughly equal proportions. The resulting gains in consumer surplus and reductions in emissions substantially outweigh the additional congestion externalities.

The environmental case for EV adoption is also location-specific. Holland et al. (2016) show that the damages avoided by switching to an electric vehicle depend on the local generation mix and on the vehicle being displaced. Relatedly, Xing et al. (2021) show that EV subsidies can be poorly targeted if they induce purchases by consumers who would otherwise have bought relatively efficient vehicles, or if inframarginal buyers capture much of the subsidy. These results do not weaken the case for electrification; rather, they imply that the social value of an EV subsidy depends on the cleanliness of marginal electricity generation, the counterfactual vehicle, and the charging profile.

Charging infrastructure is a second adoption margin. EV demand and charging-station investment reinforce each other: consumers are reluctant to buy electric vehicles without reliable charging access, while charging providers are reluctant to invest before there are enough vehicles on the road. Springel (2021) studies this two-sided market and shows that subsidy design should account for the complementarity between vehicles and charging stations. This matters for adoption and for determining the necessary grid investments. Home charging may be convenient, but it concentrates benefits among households with garages or dedicated parking. Public and workplace charging can broaden access and, as discussed in Section 4.3, can also shift charging toward hours when solar generation is abundant (Garg et al., 2026). Conversely, poorly designed time-of-use tariffs can coordinate many households into the same low-price window, creating local distribution peaks (Bailey et al., 2025a). The transport policy problem is therefore a multidimensional problem on how many chargers to build, where to build them, what prices to set, and how to manage charging decisions.

Distributional concerns are central, and are discussed further in Section 6 below. Purchase subsidies for EVs have often accrued disproportionately to high-income households, reflecting both vehicle costs and access to home charging. Evidence from California suggests that targeting subsidies toward low- and middle-income households can increase take-up among groups that would otherwise be less likely to adopt (Muehlegger and Rapson, 2022). But targeting alone is not enough if complementary infrastructure is missing, or if retail electricity rates make charging unattractive relative to gasoline. In this sense, EV policy sits at the intersection of climate policy, transportation infrastructure, retail electricity pricing, and distributional design.

5.2 Electrifying Households

Building electrification is less visible than EV adoption, but equally important. Heating, water heating, and cooking remain heavily dependent on natural gas, heating oil, or inefficient electric resistance in many regions. Heat pumps can deliver the same energy services with much less energy input, but adoption depends on local climate, building quality, installer networks, and the relative price of electricity and fossil fuels. Davis (2024) shows that heat pump adoption in the United States is driven less by income than by climate and relative energy prices, contrasting with the income gradient observed for EVs and rooftop solar. Davis (2026) provides longer-run evidence that household heating choices respond persistently to fuel prices, climate, and technology availability.

These findings have two implications. First, electrification subsidies targeted only at equipment purchase may be insufficient if households expect high electricity bills after adoption. As Borenstein and Bushnell (2022) emphasize, retail electricity prices often exceed social marginal cost because they recover fixed network and policy costs through volumetric charges. This pricing structure discourages efficient electrification and can make gas heating privately attractive even when electric heating is socially preferred. Second, building electrification interacts with demand response. A heat pump can be a flexible load if buildings are sufficiently insulated and consumers can pre-heat or pre-cool without discomfort; otherwise, electrification may simply add demand during already-stressed hours. Policies that subsidize heat pumps, building retrofits, and smart controls complement one another as long as sufficiently granular price signals are in place.

How to measure the trade-offs and successes of these policies? One challenge is that engineering estimates of savings often exceed realized savings because of rebound, installation quality, or behavioral responses. However, it is important to do a full accounting of the benefits and costs of electrification. While electricity consumption may rise, total energy use and emissions can still fall thanks to the high efficiency of electrified technologies and a cleaner grid. For example, a successful heat-pump policy may increase household electricity demand while reducing gas use and emissions, e.g., as in Bernard et al. (2024). This makes retail bills an incomplete welfare metric, especially when electricity prices include policy costs that are not aligned with marginal social costs (Borenstein and Bushnell, 2022).

5.3 Electrifying the Industry

Industrial electrification is the hardest margin. Many industrial processes require high-temperature heat, continuous operation, or specific chemical inputs that are difficult to replace with electricity. Where electrification is technically feasible, it often competes against fossil fuels on operating costs. Electricity is therefore not merely an input but a determinant of competitiveness. Plant-level evidence from German manufacturing shows that firms respond to exogenous electricity price increases by reducing electricity procurement, with substantial heterogeneity across plants (von Graevenitz and Rottner, 2022). More broadly, Lyubich et al. (2018) document large within-industry heterogeneity in energy and carbon productivity among U.S. manufacturing plants, underscoring why relative energy prices and adjustment costs can shape industrial adoption unevenly even within narrowly defined sectors.

This is where the link to long-term contracting becomes most direct. Industrial consumers considering electrification need confidence that electricity will be available at predictable prices over the lifetime of the investment. Power-purchase agreements or other long-term contracts can provide that hedge, while also supporting renewable investment upstream. In principle, this creates a natural complementarity between clean generators seeking stable revenue and industrial consumers seeking stable clean-energy costs. In practice, contract liquidity, counterparty risk, and regulatory uncertainty limit how far this complementarity has developed, as also discussed in Section 3.1 before.

The sectoral heterogeneity is large. Some low- and medium-temperature heat can be electrified with existing technologies, while other processes may require hydrogen, direct reduced iron, or other emerging technologies. Rosenow et al. (2025) emphasize that policy for industrial electrification must therefore combine electricity-price reform, infrastructure planning, and technology-specific support. A uniform subsidy per kilowatt-hour is unlikely to be enough when firms differ so much in process heat needs, utilization rates, exposure to global competition, and access to clean electricity.

5.4 Data Centers

Data centers are a distinctive electrification challenge because they represent new electricity demand rather than substitution away from direct fossil-fuel use. Their growth can support clean investment if it is matched with additional low-carbon generation and flexible operation, but it can also raise system costs and emissions if it increases fossil generation at the margin. Kay et al. (2026) estimate that existing data centers have already raised U.S. wholesale electricity prices, with substantially larger effects in regions with concentrated data-center corridors, and that future impacts depend heavily on utilization and build-out assumptions. Likewise, Fabra et al. (2026a) find that the activation of data centers raises retail electricity prices, particularly for commercial consumers. The effects are larger in regions where electricity is procured through wholesale markets, allowing higher wholesale costs to pass through more rapidly to retail tariffs. Knittel et al. (2025) show that flexible data centers can lower grid costs while potentially increasing emissions, highlighting the importance of whether flexibility is aligned with carbon as well as private system costs.

The broader lesson is that electrification policy cannot be evaluated only by counting electric loads. What matters is whether new electricity demand replaces fossil energy, whether it arrives when and where clean power is available, and whether prices and contracts transmit these system conditions to downstream investors. Electrification is therefore the other side of the renewable investment problem: clean supply and clean demand have to scale together, or each weakens the incentives for the other.

6 Social Acceptance and Distributional Implications

The previous sections have highlighted market-design, regulatory, and behavioral frictions that are slowing the energy transition relative to what technological progress and falling costs would otherwise allow. This section turns to another important obstacle: stakeholder opposition to both renewable siting and grid expansion—the phenomenon commonly labeled NIMBY (Not In My Back Yard).

Opposition comes from residents worried about the local externalities (Heim et al., 2026; Quentel, 2026)—effects on recreational amenities and landscape effects, property values, and other economic impacts (e.g., fishing communities affected by offshore wind),—from those concerned about possible health consequences (Rott et al., 2026), and from people who see no upside for themselves yet remain wary of hidden downsides (Joskow, 2021). Adding to this, growing political polarization has fed into right-wing movements that oppose energy-transition investment more broadly (Bosetti et al., 2025). These groups have mobilized effectively against renewable and transmission projects alike, and their opposition has a real role in blocking or slowing permits. Jarvis (2025) estimates the economic costs of NIMBYism and local planning restrictions in the United Kingdom using data on roughly 4,000 large wind and solar projects proposed over the past three decades. He finds that local opposition and planning constraints increased the cost of renewable investment and resulted in substantial underinvestment.

More broadly, the perceived distributional implications of the energy transition often become an obstacle to the political support that these policies need to survive. It is not enough to design efficient instruments: policymakers must also understand who wins and who loses, since only policies with social and political support will ultimately be implemented. Faced with two equally cost-effective instruments, the one with better equity properties should be favored.

The challenge is: how to proceed in the face of an equity-efficiency trade-off? For instance, energy subsidies are often intended to reduce inequality and alleviate fuel poverty, but they can also encourage excessive energy consumption and increase environmental costs (Hahn and Metcalfe, 2021). Similarly, increasing-block pricing—under which marginal prices rise with household electricity use—is often justified as a way to protect low-income consumers, who tend to consume less electricity. Yet when prices are only weakly related to marginal costs, such tariffs create an equity-efficiency trade-off (Borenstein, 2012). This concern has become more pronounced with the diffusion of rooftop solar among higher-income households. By reducing their purchases from the grid, solar adoption weakens the traditional positive relationship between household income and grid electricity consumption. As a result, increasing-block tariffs can generate the unintended effect of subsidizing electricity consumption by wealthier households (Borenstein, 2025).

The distributional consequences of the energy transition operate at several levels, and they are not uniformly regressive as the conventional wisdom might suggest. At a macro level, the displacement of fossil fuels by renewables affects electricity prices; where this translates into lower prices, low-income households benefit disproportionately, since they devote a larger share of their income to energy. The build-out of renewables can also create local jobs (Fabra et al., 2024; Hanson, 2023) and strengthen the finances of rural municipalities that otherwise have few other economic opportunities (Serra-Sala, 2026). The opposite can happen with fossil-fuel phase-outs: closing coal plants can leave affected municipalities behind, creating pockets of poverty unless the transition is accompanied by place-based policies (Fabra et al., 2026b).

Downstream, the adoption of clean technologies is a further source of distributional impact, and adoption tends to be strongly correlated with income. Because only relatively well-off households living in single-family homes can afford rooftop solar, EV home-charging, or heat pumps, subsidies meant to accelerate adoption can end up subsidizing the rich, unless carefully targeted. Borenstein and Davis (2025) show that of the $47 billion in U.S. federal tax credits granted for heat pumps, solar panels, and EVs between 2006 and 2021, the bottom three income quintiles received only about 10% of the total, while the top quintile captured roughly 60%—rising above 80% for electric vehicle credits alone.

At a finer level, distributional outcomes hinge on policy design itself. The menu of instruments is wide, and their equity implications differ substantially, often depending on where and when they are implemented, and how they are financed. For instance, Reguant (2019) shows that even for a given renewable policy (a carbon tax, a feed-in tariff, or a renewable portfolio standard), the ultimate incidence on households versus firms is not pinned down by the environmental instrument itself but by how its costs are recovered at the retail level. Using a calibrated model of the California electricity market, she finds that Ramsey-style tariffs that charge price-inelastic residential customers more than price-elastic industrial customers—a common justification for shielding industry from renewable costs—can perform worse, once the environmental externality is properly accounted for, than simply passing costs through evenly across customer classes.

Also on the policy design front, Kiribrahim-Sarikaya and Qiu (2026) show that the regressivity of solar subsidies in the US partly reflects the use of non-refundable tax credits, whose full value is more accessible to high-income households with larger tax liabilities. Making the credit refundable would raise take-up among low-income households by 16% without affecting high-income households. Moreover, an alternative subsidy scheme that covers 40% of installation costs for the lowest-income households, while reducing subsidy rates for higher-income groups, substantially redistributes benefits toward lower-income households and increases total solar generation by about 2.2% relative to the baseline 30% non-refundable tax credit.

Feger et al. (2022) highlight another distributional challenge in residential solar adoption, this time between adopters and non-adopters. Households with rooftop PV continue to rely on the grid, so their adoption does little to reduce fixed network costs. Yet because they purchase less electricity from the grid, they contribute less toward recovering those costs when network charges are largely collected through volumetric prices. The resulting shortfall is therefore shifted onto non-adopters. Raising fixed charges could offset this redistribution, but would weaken incentives to install solar. The authors instead propose combining marginal prices, fixed fees, and installation subsidies to balance efficiency and distributional objectives.

Space constraints prevent us from covering this large and growing literature further.[7] We conclude with two recurring lessons. First, distributional effects are highly context-specific, making careful quantification essential for policy design. Second, heterogeneity within income groups can be as important as differences across them, and is harder to address through income-based targeting alone (Douenne, 2020).

Reguant et al. (2025) illustrate both points for dynamic electricity pricing in Spain. Us-

[7] See Deryugina et al. (2019) and the broader special issue edited by Bisin (2026).

ing household-level income estimates that account for within-zip-code heterogeneity, they find that time-of-use pricing is progressive, while real-time pricing is roughly distributionally neutral but increases bill volatility, especially for low-income households. These effects reflect local patterns of technology ownership and electricity prices: in Spain, poorer households rely more heavily on electric heating and are therefore more exposed to high winter prices. Different heating technologies or seasonal price patterns could reverse these results. Distributional impacts must therefore be assessed case by case, accounting for local demand, weather, and technology adoption.

7 Conclusion

Together, the research surveyed in this paper points to one conclusion: the central obstacle to completing the energy transition in the power sector is no longer primarily technological. Renewable and storage costs have fallen far enough below fossil-fuel alternatives that the physical means to decarbonize the grid are largely available. What remains unresolved is the market and policy design needed to convert cheap technology into reliable, clean, financed, and socially accepted investment, on both sides of the market.

Getting contract and auction design right, and pairing it with complementary investment in transmission, storage, and demand response, is a first-order determinant of how much clean capacity gets built, where, at what cost, and how reliably the system absorbs it. On the demand side, the barriers to electrification are not uniform: EV and rooftop-solar adoption is strongly income-correlated, heat-pump adoption is driven more by climate and relative prices than by income, and industrial electrification depends as much on technology availability as on costs, so policy has to be tailored sector by sector rather than applied uniformly.

A recurring theme across both sides is that efficient market design cannot be separated from its distributional and political-economy consequences. Policies that are efficient on paper but perceived as inequitable, or that impose concentrated local costs without compensation, invite stakeholder opposition, which can delay or derail projects regardless of their social value. Equity implications are neither uniformly regressive nor easily generalized; they often hinge on when and where policies are implemented, requiring careful empirical measurement of their effects.

As we have sought to highlight throughout this survey, policy relevance makes research in this area particularly appealing: getting these market-design and policy questions right is what will determine whether the energy transition advances at the pace required, rather than stalling due to avoidable frictions. The stakes are high, and the scope for valuable research remains substantial.

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