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The Economic Impacts of Clean Energy

ABSTRACT In this paper we assess the economic impacts of moving to a renewable-dominated grid in the United States. We use projections of capital costs to develop price bounds on future wholesale power prices at the local geographic level. We then use a class of spatial general equilibrium models to estimate the effect on wages and output of prices falling below these bounds in the medium term. Power prices fall anywhere between 20 percent and 80 percent, depending on local solar resources, leading to an aggregate real wage gain of 2–3 percent. Over the longer term, we show how moving to clean energy represents a qualitative change in the aggregate growth process, alleviating the "resource drag" that has slowed recent productivity growth in the United States.

The US electricity grid is undergoing a historic transition. The share of renewable electricity in generation has begun to rise rapidly from virtually nothing a decade ago (see figure 1), supported both by policy and significant falls in the capital costs of solar and wind. This trend has been widely celebrated for the climate benefits it brings with it; when solar and wind displace coal and gas, CO_2 emissions fall.

However, both the academic literature and popular analysis have placed somewhat less emphasis on the economic impacts of the transition to a clean

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grid. Chief among these are lower wholesale power prices and a displacement of fossil fuel activity. The former is likely to lead to greater economic production, higher wages, and cheaper goods prices. The latter may cause displacement of fossil fuel employment and transitional pressures as these workers retrain and shift into other sectors.

In this paper, we assess the first impact. We begin by developing projections of all-inclusive capital costs for firmed solar, that is, solar backed by storage, in the near future. We then use these projections to construct bounds on wholesale electricity prices across the United States at a relatively fine geographic scale. We show that a move to a grid dominated by firmed solar power is likely to see substantially lower wholesale electricity prices in most areas of the United States, with power costs falling between 20 percent and 80 percent depending on solar insolation and local land costs.

In a second step, we use these price bounds in a class of general equilibrium models to estimate the impact on local wages and production of moving to a solar-dominated grid. In the medium term (out to 2040), we find a fairly substantial increase in wages (on the order of 2–3 percent nationwide), with large regional heterogeneity. Rural areas stand to benefit the most, owing to a greater share of electricity in the factor inputs of their industry concentration mixes. However, many large cities and counties in Texas and California also see average wage raises of almost 5 percent, owing to substantial decreases in wholesale prices in these sunny areas.

Finally, we consider the impact in the longer term. We outline a conceptual feature of the coming era of clean growth that is qualitatively different from the recent era of fossil-fueled growth. Namely, renewable capital accumulation relieves the aggregate drag of finite resource extraction and rising energy prices. A significant part of innovative effort since the 1970s has been directed at increasing energy efficiency to offset rising prices. When electricity comes from zero marginal cost sources, such as sunshine and wind, rising resource prices stop constraining growth. The economy's innovative resources then redirect away from energy-specific technical change to more general progress, raising the aggregate growth rate.

In making the points of this paper, we are required to make some assumptions about the future path of technology. While renewable energy is already the cheapest source of bulk energy supply at many points on the US grid, much depends on what happens to capital costs from this point forward, and in particular on continued falls in the cost of storage. We make some assumptions that we believe are reasonable, but there will be many points over which reasonable people can disagree, and we don't resile from this. Our purpose in this paper is to ask "what if?" and think about a world in which renewable energy is a cheap, abundant, and dominant source of power in the United States. We take recent technological trends in energy seriously, and analyze their impact through the lens of economic theory. The landscape is littered with the bones of prognosticators who wrote off renewable progress, and we hope not to end up in that graveyard.

RELATED LITERATURE Our approach to evaluating the economic implications of the energy transition differs significantly from other approaches in the literature, most notably Jenkins and others (2022), Bistline, Mehrotra, and Wolfram (2023), Bistline and others (2023), and Abhyankar, Mohanty, and Phadke (2021). These papers use detailed engineering and energy systems models to compute the implications of economic stimulus policies and renewable subsidies on energy prices and renewable uptake. They build analyses of supply curves and transmission from the ground up, along with modeling the use of energy in production, and study least cost investment approach pathways to achieving net-zero under various technological assumptions and policy scenarios. The literature around energy systems models is vast and influential (see Pfenninger, Hawkes, and Keirstead 2014 for a review). Recent applications of this approach to specifically studying the labor market impacts of renewable penetration include Jenkins and others (2021) and Mayfield and others (2023). Complementary to this approach is empirical work by Hanson (2023), who measures the local labor market effects of initial exposure to coal production.

Instead, we use projections of firmed solar capital costs in the near future to develop spatial bounds on future wholesale prices, and then incorporate them into a general equilibrium spatial model. In this sense, our approach is most closely related to our current work in Arkolakis and Walsh (2023). However, instead of developing a model of the grid and transmission of energy across space, we focus on the local bounds as a measure of energy cost changes across space. We then develop sufficient statistics to trace the impact of electricity price shocks onto wages at fine levels of disaggregation, without actually having to estimate and solve a fully specified economic model. We view this as complementary to the successful energy systems modeling approach above, as while we abstract from the detail and computational rigor imposed by these models, our simpler approach has the advantage of being readily interpretable, and can act as a basic starting point to shape analysis and policy.

There is important economic literature that builds more aggregate macroeconomic models to study the energy transition. Integrated assessment models have long studied the interaction between fossil fuel extraction and the macroeconomy, beginning with the Dynamic Integrated Climate-Economy

(DICE) model of Nordhaus (1993), and updated most recently in Barrage and Nordhaus (2024).[1] Work by Desmet and others (2021), Bilal and Rossi-Hansberg (2023), and Cruz and Rossi-Hansberg (2024) has pushed this literature to disaggregate the effects of climate change and production shifts into heterogeneous spatial impacts within countries, while maintaining the discipline imposed by general equilibrium in the aggregate.[2] In addition, recent work by Mehrotra (2024) uses updated technology cost assumptions to show that the macroeconomic costs of transitioning to a net-zero economy are far smaller than supposed even recently. Our work attempts to add to both of these research strands.

A separate body of literature endogenizes the direction of technological change in energy innovation, building off the foundational theory by Acemoglu (2002) and applied to the context of energy and the environment in Acemoglu and others (2012) (see Gillingham, Newell, and Pizer 2008 for a review of earlier models). This literature continues to grow, with other important papers in this direction being Lemoine (2024), Känzig and Williamson (2024), and Acemoglu and others (2023). An influential paper by Hassler, Krusell, and Olovsson (2021) models the slowdown in broader innovation and the increase in energy-saving technical change since the energy price shocks of the 1970s. We build on this modeling framework in the final section and show that when energy is provided by accumulable capital, as in the case of renewables, rather than exhaustible fossil fuels, innovation resources can be redirected to broad innovation and increase the aggregate growth rate.

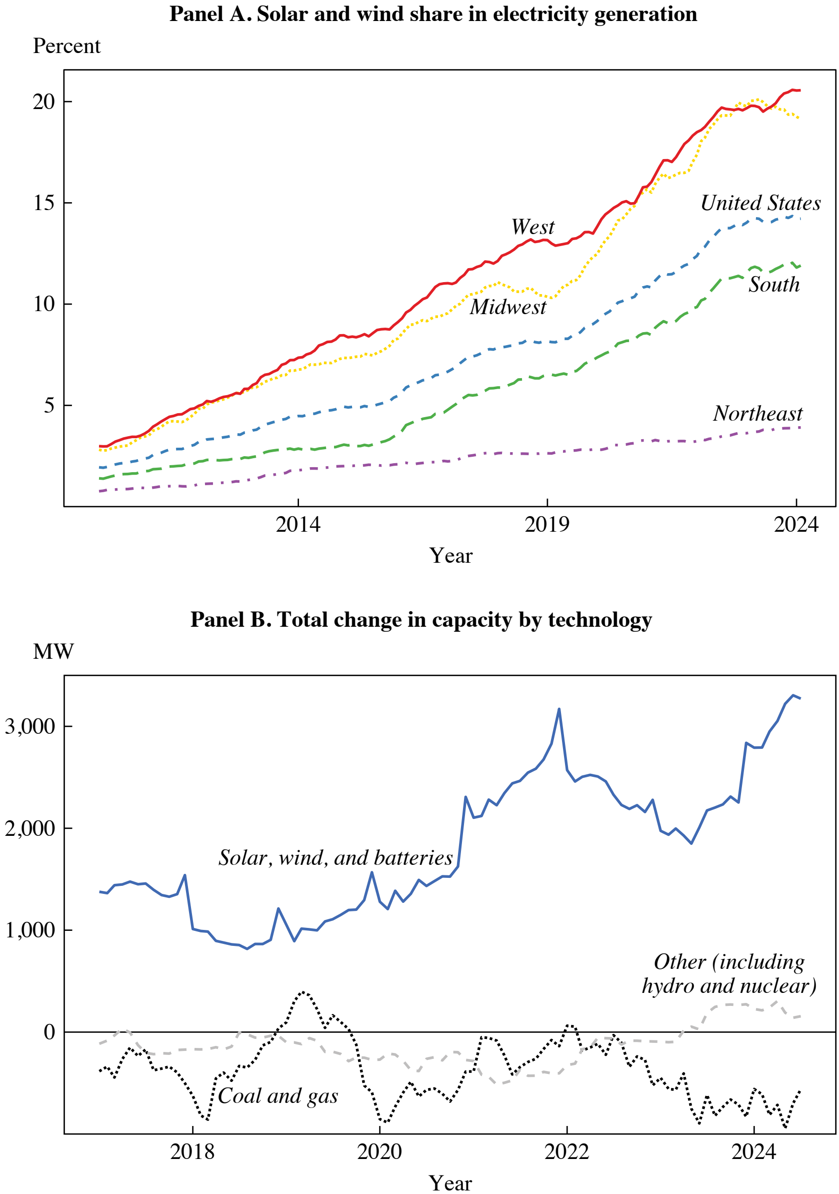
I. Wholesale Power Prices in the Medium Term

Renewable energy has begun to grow rapidly in the United States. Figure 1 shows that the share of electricity produced by wind and solar has risen in all regions in the United States, from virtually nothing in 2010 to around 14 percent in 2024, with several regions seeing much higher penetration. In panel B we show the aggregate flows of new capacity into renewables and nonrenewables. The increase in electricity generation is being driven by rapid increases in nameplate capacity for solar, wind, and batteries. Fossil

1. A strand of the literature emphasizes the endogenous effects that access to electricity has on output through energy prices and incorporates supply and demand of energy in a macroeconomic model (Nordhaus 1973; Kypreos and Bahn 2003; Edenhofer and others 2013).

2. See Desmet and Rossi-Hansberg (2024) for a recent review.

Figure 1. The Renewable Transition in the United States



Source: US Energy Information Administration (EIA).
Note: Panel A shows the twelve-month moving average of the monthly share of total electricity at the regional level coming from solar and wind. Panel B shows the twelve-month moving average of the change in nameplate capacity by technology.

fuels as a group are shrinking, while hydro and nuclear remain roughly stable. In online appendix A, figure 17, we break these flows out further. Within fossil fuels, coal has been rapidly exiting the grid, while gas capacity continued to be built up until 2022 at roughly the same speed as wind energy, though in the last year new investment has dropped off rapidly (see also figure 19 in online appendix A). Solar investment has been consistently increasing over the last ten years, to the point that in 2024 it currently accounts for the most new capacity investment out of all power technologies. Utility-scale batteries are a very recent addition to the grid, but in the last four years they have begun to scale up rapidly, supporting the intermittent energy flows of solar and wind.

Analyzing the long-run price impact of moving to a renewable-dominated grid is a challenging endeavor. The US electric grid is enormously complicated, consisting of many interlocking organizations and systems. The transition to renewables will have heterogeneous impacts on prices in different locations, depending on local renewable resources, the pricing mechanisms of local utilities, and the strength of local transmission networks, a point we explored in earlier work (Arkolakis and Walsh 2023).

Here, we try to cut through some of this complexity. We consider a simple bounds approach that is helpful as a guide to shape thinking. This approach abstracts from most of the grid's complexity and starts from the observation that capital costs are the dominant direct cost in supplying renewable energy.[3] Operating costs of renewables are negligible, and depreciation and maintenance expenses have proved to be very low. As a result, upfront capital costs determine the economics of supply. In deregulated markets, particularly those that have implemented locational marginal pricing, such costs place an upper bound on future steady-state wholesale prices at any point on the grid.[4]

To make this point, we first note that renewable power generation capital is unlike conventional fossil fuel generation assets in several respects. Three stand out in particular and form the basis for our analysis in this section.

3. Throughout this paper we use renewable energy to refer solely to photovoltaic (PV) solar power and onshore wind. These technologies are widely considered to be the dominant technologies in the medium term, with offshore wind playing a more limited role in the United States due to geography and regulatory constraints. Other renewable technologies are either early stage and not cost competitive with PV and onshore wind (such as geothermal and wave energy) or, like hydroelectricity, are mature with limited scope for expansion.

4. We abstract from local distribution costs and fixed network charges, which show up in retail prices for this analysis, and return to them briefly in section II.E.

First, renewables are modular. By this we mean that the generating unit comes in small sizes available at constant fixed prices, many of which are strung together to form a plant. In contrast, fossil fuel assets such as coal-fired power stations tend to be large, complex installations with substantial fixed costs. This historically led to a structure of centralized generation in large plants, with transmission lines strung to load centers. The modularity of renewables makes it easier to build them in smaller plants and facilitates a much more decentralized grid. While large installations certainly exist, recent renewable projects tend to be of varying small and medium sizes and are more dispersed around load areas.[5]

Second, fuel costs are zero, and the productivity of the asset depends mainly on where it is placed in space. Placing a solar panel in the sunshine or a wind turbine on a gusty ridge occasions zero direct input costs over the life of the asset. However, electricity output will differ widely across the country. The productivity of a solar panel in terms of total annual electricity production is almost two times higher in Arizona than in Maine (see figure 18 in online appendix A). The divergence in wind potential across space is even starker. Average wind power output is a cubic in average wind speeds. As a result, a wind turbine in the windiest locations, such as South Dakota, will produce around five times the electricity of the least windy locations, such as Florida.

Third, renewables are intermittent. As renewable penetration increases, more backup from storage or rapid-response peaking plants is required. In what follows, we will assume that in the medium run, renewables are completely backed up by battery storage and examine the cost implications.[6]

Combining these assumptions allows us to develop a simple asset pricing equation that must hold in the long run wherever renewables are installed on the grid. Let $Q_{\ell t}$ denote the all-in capital cost of a megawatt (MW) of firmed renewable capital in location ℓ at time t, whether solar or wind, inclusive of storage costs. Let θ_ℓ be the expected annual output of the capital unit in megawatt-hours (MWh), and $p^{\varepsilon}_{\ell,t}$ the average price of a megawatt-hour of electricity in location ℓ at time t. Assuming there are annual depreciation

5. We will also assume that their modularity by its very nature encourages a reduction in the market power of large incumbents. Bahn, Samano, and Sarkis (2021) caution that if renewable investment is developed primarily by legacy fossil fuel incumbents, the effect on wholesale prices of lower generation costs could be muted.

6. Around half of the current solar projects in the interconnection queue are hybrid plants with a storage component, up from none just five years ago; see Rand and others (2024).

costs that occur at rate δ, and a cost of financing $R_{0\to t}$, where this should be read as the cumulative compound interest rate from year zero until year t, namely, $R_{0\to t} \equiv \prod_{\tau=1}^{t}(1 + r_\tau)$, we can write

$$(1) \qquad Q_{\ell t} = \sum_{\tau=1}^{T} R_{t\to t+\tau}^{-1}\left(1-\delta\right)^{\tau}\theta_{\ell}p_{\ell,t+\tau}^{\varepsilon},$$

where T is the lifespan of the project (typically around thirty years for solar panels and somewhat longer for wind energy). Appropriate adjustments can be made to incorporate longer times to build; typically, once approved a new solar plant can be constructed in eight to eighteen months, with a wind project taking somewhat longer (Richardson 2023).

Crucially, this equation does not have to hold everywhere on the grid in the medium term. There will be many places where wholesale power costs are lower than what would be implied by local capital costs, particularly in dense urban regions and places with poor renewable resources. In that case, equation (1) would be an inequality, with the left-hand side being greater than the right. In such places, electricity will be imported from other low-cost regions, with the ability to access their low prices driven crucially by transmission capacity. In addition, equation (1) may hold for solar in sunny regions, and wind in windy regions, but it does not necessarily have to hold for both at the same time.

In places where it does hold, we can solve for the steady price of power that must occur in these regions, by setting the wholesale electricity price $p_{\ell,t+s}^{\varepsilon} = p_{\ell}^{\varepsilon}$ to its medium-run average and then writing

$$(2) \qquad p_{\ell}^{\varepsilon} = \bar{Q}_{\ell}\left(\theta_{\ell}\sum_{\tau=1}^{T} R_{0\to\tau}^{-1}\left(1-\delta\right)^{\tau}\right)^{-1},$$

where we let $\bar{Q}_{\ell}$ be the upfront medium-run investment cost of renewable capital, backed up by storage to address its inherent intermittency.[7] This shows that in the long run, in places where renewables are installed, there are two essential determinants of electricity prices across space: upfront capital costs $\bar{Q}_{\ell}$ and potential expected annual output θ_{ℓ}.

7. This formula is very similar to what is often called the levelized cost of energy (LCOE) in the literature, with the main difference being how depreciation expenses are treated.

Leaving aside potential for the moment, one can think about breaking down the capital cost into several components that we can size across different areas:

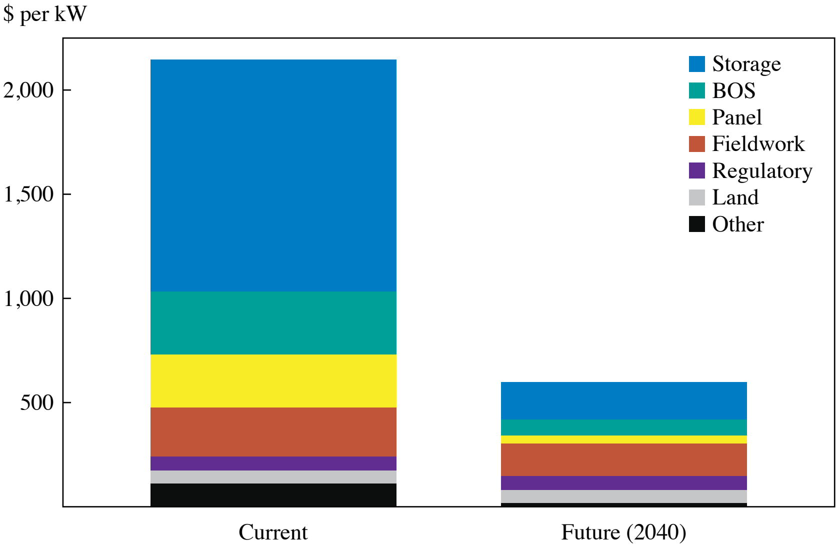
$$(3) \qquad \bar{Q}_\ell = \text{Plant Capital Cost} + \text{Balance of System Cost} + \text{Construction Cost} + \text{Land Cost} + \text{Regulatory Cost} + \text{Storage Cost.}$$

We can try to get a handle on each element of these components and think about how they might change into the future. For the rest of the paper, we are going to focus on solar power. While we expect wind power to be an important part of the generation mix of the future, the recent explosion of solar power and its pairing with lithium-ion storage lead us to believe that it will be the dominant technology. Its capital costs have been falling faster than the capital costs of wind for a prolonged period, and in many places, itis now the cheapest form of unsubsidized bulk energy supply. As can be seen in online appendix A, figure 19, the committed and under-construction project pipeline in the United States is dominated by solar projects and short-duration lithium-ion storage, with wind a distant second (and fossil fuel investment being virtually absent). Nonetheless, the techniques we use here can easily be adapted to study the impact of wind energy, and we do so in online appendix C.

In figure 2 we show the current breakdown of an installed unit of firmed solar capital at utility scale. Our source for this is the National Renewable Energy Laboratory (NREL) report, *U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks* (Ramasamy and others 2023). We make three small adjustments to the estimates of this report. First, we use the data on price for solar panels coming from Bloomberg New Energy Finance (BNEF) in 2023, reflecting significant falls in 2023 relative to 2022 (the data used by NREL). Second, while NREL includes land leasing costs in operation and maintenance, we cumulate them and discount them to include them in upfront costs. We separately include depreciation and maintenance in δ on the right-hand side of equation (2). Last, we extend the amount of storagefor each unit of solar from 2.5 hours to eight hours, using costs from BNEF in 2023.

Allowing for eight hours of storage per unit of solar capital effectively makes each hour of sunlight captured in any day across the year completely dispatchable on demand. The average daily output of a 1 kilowatt (kW) solar panel across the United States is 4 kilowatt-hours (kWh), with substantial

Figure 2. Firmed Solar Project Costs Now and in the Future



Source: Current uses data are from NREL in Ramasamy and others (2023) and authors' calculations. Future data are based on authors' calculations.

Note: Figure shows the breakdown of upfront installation costs of a kilowatt of solar power. Prices are in 2023 dollars.

heterogeneity across the country (see figure 18 in online appendix A). This rises to around 6 kWh in the summer months and falls to 2 kWh in the middle of winter. With eight hours of storage for a 1 kW panel, up to 8 kWh of output can be stored, so that solar power can provide for around-the-clock power (some panels supply while the sun is up, others dispatch their stored output in the evening or in the early morning hours), with a buffer for intraweek variability.

It is worth stressing this, since there is often some confusion in popular discussion of this point. Fully dispatchable solar power does not require twenty-four hours of storage for each solar panel. All it requires is enough storage so that each hour of sunlight captured in a day can be dispatched at will. In a crude example, having 5 kWh of usable sunlight a day means that 5 kW of solar panels, each with five hours of storage, can supply 1 kW of power continuously throughout the day. Increasing the storage buffer to eight hours or building an extra 3 kW of panels with five hours of storage, provides a reserve for cloudier days.

What about seasonal variability? The same location that has an average 5 kWh of sunlight throughout the year might see 3 kWh in winter and 7 kWh in summer. Lithium-ion batteries are not ideal for long-term storage to offset this seasonal variation, as efficient use of the asset requires continual charging and discharging cycles. To the extent that gas backup is less available in the winter in a future renewable-dominated grid, this issue can be dealt with via the combination of overbuilding and curtailment. This involves building enough firmed solar to meet winter demand levels, and then in summer curtailing (or shutting off) the excess generation.[8]

In practice, for our exercise what this means is lowering the "capacity factors" of firmed solar. A capacity factor tells us what fraction of an average day 1 kW of nameplate capacity can generate 1 kWh of power, which for solar typically ranges on the order of 0.2–0.25, depending on geography. We will proceed in this paper by abstracting from the issue of seasonable variability. However, we found that applying the curtailment estimates from Arkolakis and Walsh (2023) to lower firmed solar's capacity factor, as well as increasing the storage buffer from eight to twelve hours, do not meaningfully change the results below.[9]

We now discuss how we project the current costs of firmed solar power out to 2040.

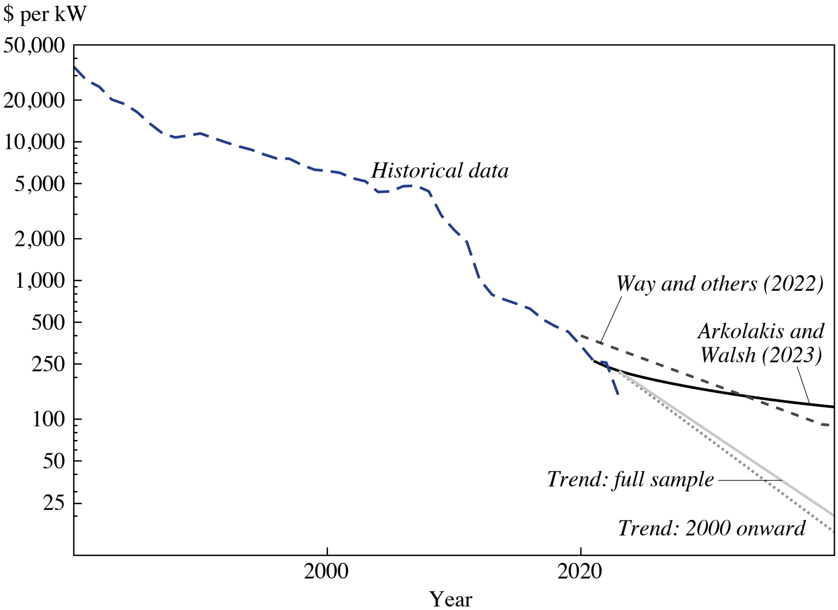
We begin with the cost of the panels. In figure 3 we show the historical price of a solar panel per watt (W) of output, which corresponds to the "panel" cost in figure 2.[10] The decline in price for panels has been extremely fast and prolonged by any standard, averaging 11 percent annually in real terms since 1980, and 13 percent since 2000. This has caused the price of panels per watt to decline about a hundredfold between 1980 and 2020. It is safe to say that no one in previous decades imagined we would be here in 2024,

8. Of course, it is worth noting that given enough time, the market would likely find a use for the excess power in the summertime, and it would not be wasted. Endogenously lower summer prices would send a signal to encourage flexible demand to ramp up in the summer. One can already imagine seasonal hydrogen fuel production, desalination, and flexible computation loads responding to lower summer electricity prices. We thus think of the eight-hour benchmark battery storage scenario we consider as fairly conservative. Tong and others (2021) show that when optimally mixing renewable wind and solar energy production—even with a three-hour storage capacity—all the major economies in the world in terms of total GDP can offer grid reliability (share of demand met by supplied renewable electricity) of about 80 percent and upward. Increasing the storage buffer to eight hours takes this above 90 percent for most countries (interpolating between the authors' estimates for three and twelve hours).

9. We find an increase of 20–30 percent in the wholesale price bounds across space in either of these exercises, which still implies significant price drops against current prices for most of the United States.

10. Our World in Data, "Solar Photovoltaic Module Price," https://ourworldindata.org/grapher/solar-pv-prices.

Figure 3. Solar Module Prices and Projections



Source: Historical data are from Our World in Data, which are a composite of IRENA (2023b), Nemet (2009), and Farmer and Lafond (2016); Arkolakis and Walsh (2023); and Way and others (2022).

Note: "Trend: full sample" takes the average decline in the historical data and projects out prices from 2023 onward. "Trend: 2000 onward" does the same using the average decline in the post-2000 data. The data point for 2023 is not included in these projections.

with solar now the cheapest form of unsubsidized bulk energy supply in most parts of the world. The question that confronts us now is where this trend is heading.

There are a number of analyses in the literature that attempt to project solar costs into the future. One of these is our own (Arkolakis and Walsh 2023), which uses a structural model of the world economy's adoption of renewables, where progress in capital costs is driven by "learning by doing," which is disciplined with grid-level parameters. Another influential piece in policy circles has been Way and others (2022), which estimates statistical experience curves for a range of technologies, including solar, and back tests these against historical data. We plot both of these projections out to 2040 in figure 3. Both of these analyses predict a slowing in the trend rate of decline, and for largely the same reason: As solar energy's share of the world generation mix expands to significant levels, the next doubling of capacity becomes progressively harder to achieve. While this is a reasonable assumption, both of these projections look to have already been proved too conservative by the stunning data in 2023 (visible on the graph), when costs declined almost 45 percent in a single year. Historically, one could have done much worse at any point in the last forty years than just drawing a straight line in log space and pushing that forward a decade. Such naive forecasts are also included in figure 3.

Projecting costs at the historical rate of decline leads one to incredibly cheap capital costs by 2040. Could a solar module really cost $20 per kilowatt, or even $10? This seems somewhat fanciful from our vantage point in 2024. The raw materials alone currently run to more than that, long before we think about the costs involved in production. At current prices, the silicon in a 700 W module costs around $5. Then there is $6 of aluminum for the frame, and $9 of copper for the wiring. This is to say nothing of the glass, which currently makes up 75 percent of the weight of a 35-kilogram 700 W panel.[11]

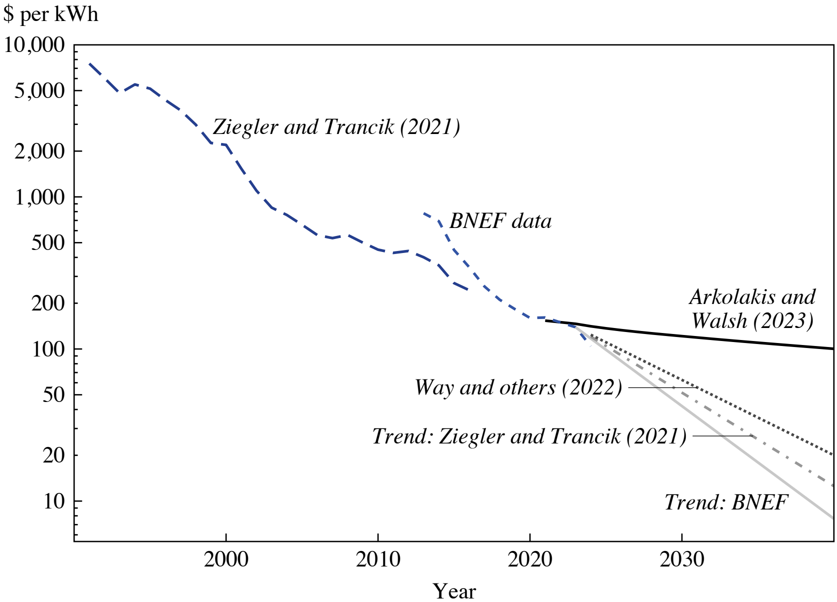
But a little imagination can get us a long way from the $145 of mid-2023 to $20 in 2040. First, both research and commercial efficiencies of solar panels have been steadily improving for decades. Perhaps the most famous figure ever produced by the NREL charts the progress of record solar cell efficiencies by panel type (reproduced in figure 20 in online appendix A). Current commercial solar cell efficiencies are around 20 percent. Improving this to 30 percent, well within the realm of current lab efficiencies for multijunction and hybrid cells, would lower cost by a third for the same materials. Stripping out raw materials, as would be possible in a move from monocrystalline to thin film or hybrid perovskite technologies, could lower costs by a similar magnitude. Due to the fact that disparate improvements propagate multiplicatively to final cost, a further twofold increase in manufacturing efficiencies, something that has been achieved many times in the last few decades, suddenly gets us in the ballpark.

For this exercise, we will take a middle road and assume a cost decline that places the 2040 cost of solar cells halfway between naive trend extrapolations and the current vintage of model projections, so that a 2040 solar panel costs $40 per kilowatt.

Battery prices are today the largest component of a unit of firmed solar power. Eight hours of storage capacity from lithium-ion batteries currently adds $1,100 to the cost of a kilowatt of solar power. While certainly expensive, this cost has been declining precipitously, by between five and seven

11. Our estimates for these numbers use data from Dominish, Florin, and Teske (2019).

Figure 4. Battery Pack Prices and Projections



Source: Ziegler and Trancik (2021); Way and others (2022); Arkolakis and Walsh (2023); and BNEF.
Note: "Trend: Ziegler and Trancik (2021)" takes the average decline in this data series and projects it out from 2023 to 2040. "Trend: BNEF" does the same using the average decline in the BNEF data.

times in just ten years, as shown in figure 4. Going back thirty years, the cost of lithium-ion storage has fallen around fiftyfold. This is around as fast as the price of solar modules has declined, and among the fastest cost declines recorded for any industrial good in the United States. Assuming the trend continues for the next sixteen years leads to around $10 per kilowatt. We will choose to be more conservative than these log linear extrapolations and use the numbers from Way and others (2022), which leads us to around $20 per kilowatt by 2040, that is, $160 for an eight-hour battery per kilowatt. We note, however, that as with the huge decline in solar panel prices in 2023, battery prices have already diverged below these projections, falling 14 percent from 2022 to 2023, and a further 25 percent to mid-2024.

Balance of system (BOS) costs are the additional electrical components, such as transformers, module racks, and inverters, which are needed to complete the installation and connect to the grid. In historical forecasts of solar price declines, these costs were seen as a crucial bottleneck hampering continued price falls. In practice, however, being mainly manufactured components, they have fallen quickly in price as well. NREL estimates that these declined by about 60 percent between 2013 and 2023, or a yearly rate of decline of 8.7 percent (Ramasamy and others 2025). We will assume this continues out to 2040.

Labor used in construction ("fieldwork" in the terminology of NREL) consists of the labor required to mount, install, and connect the panels to the grid. While falls in the cost of labor itself are unlikely, there has been consistent learning by doing in installation labor at both the utility and residential scale in solar energy that has improved overall construction efficiency in recent years. Then too, as the cost of panels and batteries decline, the economics of larger installations becomes more feasible, as some of this labor is a fixed cost and can be spread over more units.[12] These forces are difficult to size quantitatively. We assume that the cost of fieldwork per kilowatt declines by a third by 2040, but little changes in our analysis if this component of cost remains constant.

Land lease payments to host solar farms are currently a relatively small fraction of costs. This, however, may change in the future, as land prices are unlikely to fall significantly in coming years. As other components decline, land becomes increasingly important. Moreover, it is the only component of cost that differs significantly across space. We use data from Nolte (2020), who provides high-resolution estimates of private land values. We average these at the county level (estimates presented in online appendix A, figure 21). Land values differ significantly across the United States, ranging from $1,000 per hectare in remote rural areas to over $1 million per hectare in New York City. These magnitudes significantly affect the viability of solar projects in densely populated areas. We assume that these land prices will be unchanged in real terms in 2040.

The "regulatory" component computes the costs of applying for permits and environmental approvals, which we leave unchanged to 2040. NREL additionally lists a category of "other" costs involved in project construction, consisting of sales tax, management, and profit. Since conceptually these costs are percentage additions to the final installed project cost, we assume they remain proportional in 2040 and scale down accordingly. The final wholesale power price bound is presented in figure 2. A unit of firmed solar power falls from $2,145 in 2024 to $570 in 2040.

12. Automation of installation and replacing construction labor with robots is also a nascent possibility; see AES, "AES Launches First AI-Enabled Solar Installation Robot," press release, July 30, 2024, https://www.aes.com/press-release/AES-Launches-First-AI-Enabled-Solar-Installation-Robot.

Land, labor, and regulatory costs eventually become the dominant components of installed capital costs, accounting for more than half of total cost by 2040. Beyond this point, the power of further falls in solar module, battery, and BOS costs to push down the steady-state wholesale price of power becomes muted. Indeed, without significant efficiencies in installation labor and big increases in module efficiency that would allow a significant reduction in land costs, it is very difficult to see how solar project costs go below \$200–\$300 per kilowatt even in the very long run. We state this with some caution, of course, noting the long history of failed predictions and overages on how low solar costs could conceivably go.

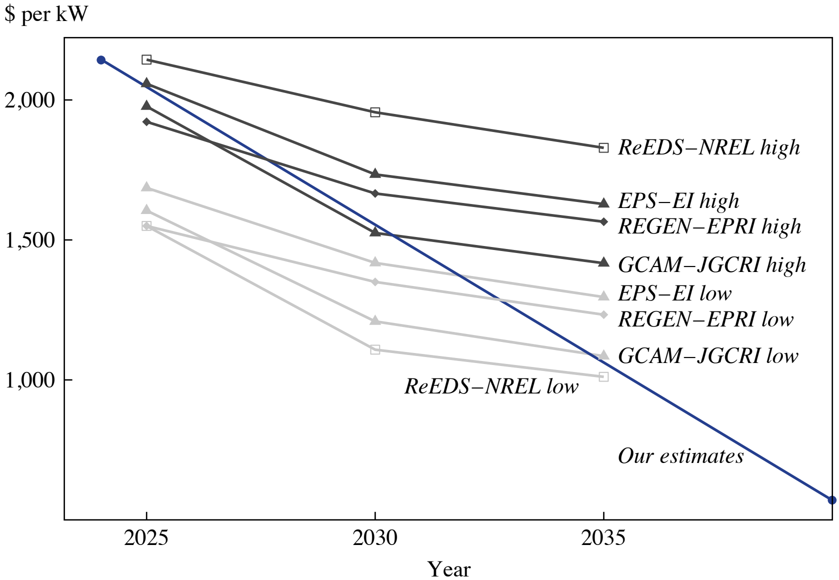
Comparison of our estimates to leading projections in the energy systems literature discussed above reveals that our estimates are optimistic but not unrealistic. In figure 5 we juxtapose our predicted firmed solar capital costs to estimates from various simulated energy systems models in the literature, as summarized by Bistline and others (2023). We see that our estimates mostly agree with others in the literature by 2030, but then the decline in our estimates continues to new lows while declines in all other estimates tend to peter out from 2030 to 2035. At the heart of this difference is that all those models assume that both solar photovoltaic (PV) and battery cost declines will start significantly slowing down in the next decade. We also assume that the declines will continue at a slower pace than recent decades, but that this pace will still be quantitatively significant.

We now use our estimated 2040 capital cost in conjunction with equation (2) to compute the bound on wholesale prices in 2040. To do so, we first need estimates of θ_ℓ, the average amount of electricity produced by a panel in a year at different places in the United States. This is provided by the Global Solar Atlas for the United States at a very granular level, and we plot estimates of panel output in online appendix A, figure 18.[13] The spatial variation is marked: A 1 kW system in Southern California produces 1,825 kWh a year. The same system in Seattle produces 1,277 kWh a year. This significantly impacts the future implied prices across space, since in sunnier areas it translates directly into a lower price per kilowatt-hour needed to justify the upfront capital cost of equation (3).

Last, we assume a long-run financing cost of 5 percent, which is consistent with current estimates from the International Renewable Energy Agency for solar energy in the United States (IRENA 2023a). Of course, this depends

13. Global Solar Atlas, "Map and Data Downloads: USA," under "Global Photovoltaic Power Potential by Country," https://globalsolaratlas.info/download/usa.

Figure 5. Firmed Solar Cost Comparisons



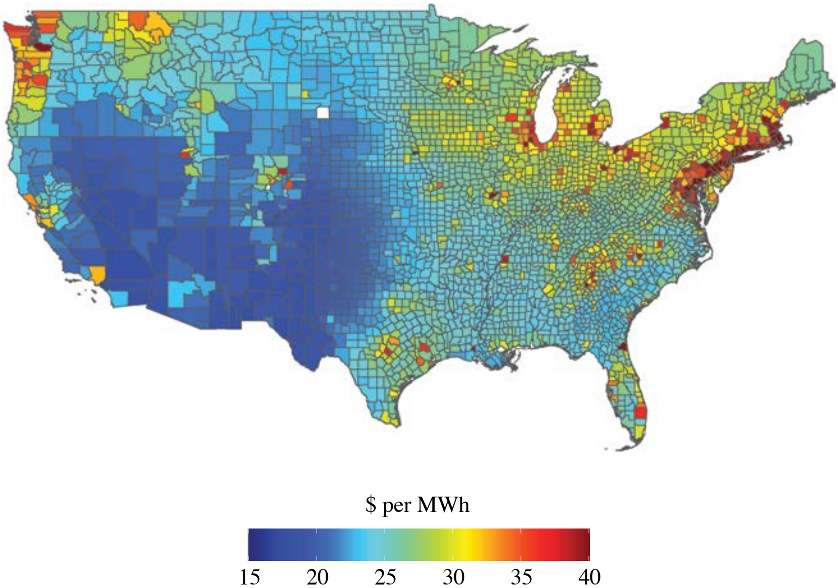
Source: Bistline and others (2023); Cole and Karmakar (2023); and authors' calculations.

Note: The figure shows the comparison of firmed solar capital costs based on our calculations and different models in the literature, using data from appendix S1 of Bistline and others (2023). We extract solar PV estimates by different models and add low and high estimates of battery capital costs from estimates by NREL in Cole and Karmakar (2023) by multiplying their four-hour battery cost estimates by two, to obtain an eight-hour estimate. The models detailed here are the Energy Policy Simulator by Energy Innovation (EPS-EI), the Global Change Analysis Model by the Joint Global Change Research Institute (GCAM-JGCRI), the US Regional Economy, Greenhouse Gas, Energy (REGEN) model by the Electric Power Research Institute (REGEN-EPRI), and NREL's Regional Energy Deployment System (ReEDS-NREL). Prices are in 2023 dollars.

on a return to a relatively low interest rate environment in 2040; any further outbreaks of inflation in the next decade would raise this number.

The final implied price bounds from equation (2) incorporating all this information are plotted at the county level in figure 6. Prices range from around \$20 per megawatt-hour in sunny, sparsely populated areas, to above \$35 in densely populated urban corridors, with the payroll-weighted average being \$27. In most parts of the country, this represents a significant decline in wholesale prices in 2024. We collect current wholesale prices from the US Energy Information Administration (EIA) for the major regional transmission organizations (RTOs) and independent system operator (ISO) pricing hubs, as well as regions that do not use locational marginal prices, and then plot the implied price decline in online appendix A, figure 22. Price declines range from 20 percent in the densely populated parts of the

Figure 6. Future Implied Wholesale Price Bounds Across the United States



Source: Global Solar Atlas and authors' calculations.
Note: Figure shows the implied bound on wholesale prices using equation (2) for 2040. Prices are in 2023 dollars.

Midwest, to 40 percent in New York and the South, and all the way up to 80 percent in California, Texas, and much of the West.

The advantage of taking this bounds approach is that we can say something about future prices with a minimal set of assumptions. As we will see below, knowing the bounds on electricity prices allows us to derive a full set of general equilibrium wage responses and assess the macroeconomic impact of the renewable transition. The disadvantage is that we can say nothing about quantities. We cannot predict how much firmed solar capacity will be installed in any particular place, nor even a potential range of quantities. For that, one really does need a fully specified structural model of the US economy, complete with assumptions about local demand curves for electricity in general equilibrium and stocks of alternative technology capital like natural gas and nuclear (for example, Arkolakis and Walsh 2023).

Nevertheless, the advantage of our approach is significant, and so it is worth probing a little further into the minimal assumptions the analysis above rests upon.

First, let us note that our methodology does *not* assume that the grid of the future is fully supplied by firmed solar. Even with large amounts of battery storage, there will still likely be a need for gas backup in certain areas and at certain times for years to come. Second, the fleet of US nuclear plants are fully depreciated at this point, and they have a minimal marginal cost of supply. While the existing plants are relatively old on average, there appears to be little technical barrier to extending their operating lifetimes for decades more.[14] The electricity they produce is carbon-free and also free of the many additional pollutants pumped into the atmosphere by coal and natural gas turbines.[15] As such, they are a valuable asset in a world of clean power and will likely continue to supply up to 800 terawatt-hours (TWh) for many years to come, enough for 20 percent of the current US electricity demand.[16]

Instead, what we assume holds is a simple no-arbitrage condition: The low fixed costs of firmed solar, and its relative ease of construction, place a ceiling on what local generators can charge in the medium term without inducing additional solar entry. Behind this is the implicit assumption that marginal entry into new solar within each county is elastic, so that if wholesale electricity prices rise (say, because demand increases), new firmed solar can easily be constructed locally. One might well ask if this is true in all areas in the United States.

In particular, a dominant concern in popular analyses has been whether there is enough land for the renewable energy transition. Is there enough land available locally for elastic entry to be a reasonable assumption? In the aggregate, available land is clearly not a binding constraint. The United States generated 4,178 TWh of electricity in 2023 according to the EIA.[17] Using data from the NREL on developable land area for solar power in the lower forty-eight states of the continental United States, there are over 112 terawatts (TW) of potential solar capacity available in the NREL's reference case. Total current US power demand represents about 2 percent

14. See, for example, US Department of Energy (2020).

15. Given that it is somewhat difficult to adjust nuclear power plant output rapidly, nuclear plants are particularly unsuitable to a regime dominated by unfirmed solar power, where high output during the day pushes down midday prices dramatically. In recent times, California and Australia, with their excellent solar insolation, have seen protracted negative price events during the day, with generators having to pay to bid into supply. To us, this seems like a clearly temporary phenomenon as battery storage scales up.

16. US Department of Energy, "Nuclear Reactor Technologies," https://www.energy.gov/ne/nuclear-reactor-technologies.

17. EIA, "Frequently Asked Questions (FAQs): What Is U.S. Electricity Generation by Energy Source?" last updated on February 29, 2024, https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

of developable solar capacity in the continental United States (Lopez and others 2024).[18]

But what about locally? We can use data from the Quarterly Census of Employment and Wages (QCEW) to form a detailed picture of the county industrial structure at a relatively fine level of industry disaggregation—six-digit North American Industry Classification System (NAICS) codes, or around one thousand different industries.[19] Some industries, such as mining, milling, and manufacturing, are relatively electricity intensive, using large amounts of power for production. Other industries, such as legal services and personal care, use comparatively little electricity. Differences in local industry structures then lead to differing amounts of power usage across space. We can get a measure of relative industry electricity demands from aggregate sectoral data in the input-output tables, which record how much each industry spends on electricity annually. Assuming this is approximately proportionate at the local level allows us to form a county-level estimate of demand for electricity from industrial and commercial use. To complete the picture, we add residential demand, assuming this is proportional to county population.[20]

In figure 7 we plot an estimate of county-level demand for electricity in 2023 against the fraction of local developable solar potential capacity from the NREL data on solar supply curves that would need to be developed to meet that demand.[21] We use the NREL's reference case to form county-level estimates of developable solar capacity (Lopez and others 2024). Under this case, many areas are excluded on a very fine geographic scale from developable potential: built up urban areas, conservation easements, federal Department of Defense lands, infrastructure setbacks, regulatory bans and moratoriums, and elevated or unsuitable terrains.

We estimate that the vast majority of counties in the United States would be able to meet their power needs locally, without the need for transmission

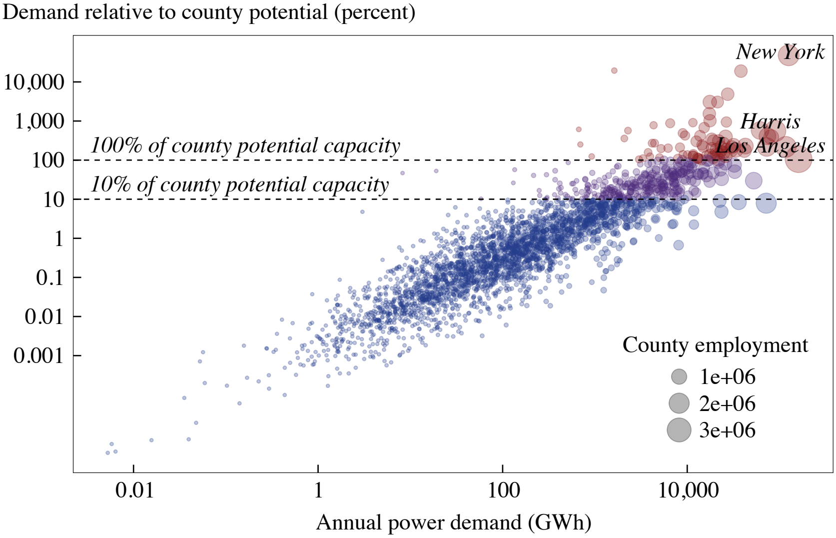
18. Total developable solar capacity in the reference case of the NREL data set represents around 30 percent of land area in the continental United States. As such, meeting current demand solely from solar power is feasible using less than 0.6 percent of total land in the continental United States, not inclusive of rooftop potential. For reference, this would be around five times the land currently used for golf courses.

19. Bureau of Labor Statistics, "Quarterly Census of Employment and Wages," under "Employment and Wages Data Viewer: NAICS Industries by Geography—NAICS 6-Digit Industries, One Area," https://data.bls.gov/cew/apps/data_views/data_views.htm#tab=Tables.

20. While this will not be exactly true, as the local climate will have an impact on electricity use per household, it is a reasonable first step.

21. NREL, "Solar Supply Curves," https://www2.nrel.gov/gis/solar-supply-curves.

Figure 7. Current County Demand Relative to Local Potential

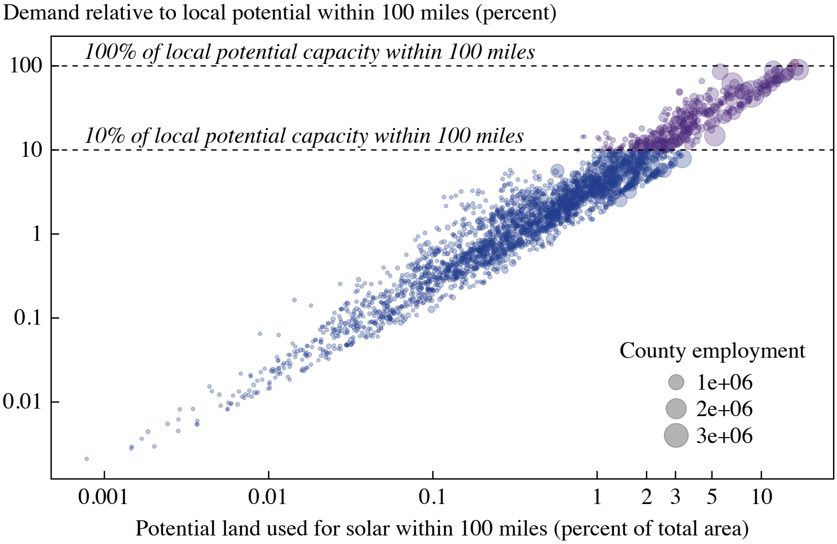


Source: NREL; Global Solar Atlas; QCEW; Bureau of Economic Analysis; and authors' calculations.
Note: Data on local potential are from the NREL estimates of developable capacity, in their reference case (Lopez and others 2024), combined with insolation data from the Global Solar Atlas. Local demand is estimated using the local county employment mix by industry from the QCEW, combined with sectoral electricity usage in the 2017 detailed input-output tables from the Bureau of Economic Analysis.

from other counties. Of the 3,109 US counties, 2,705 could meet all of their current power demand by developing less than 10 percent of the land the NREL estimates could be converted to solar power production. We note that this is far less than 10 percent of the actual land of the county. Another 312 counties could conceivably run entirely on local supply but would need to develop much or most of the potential capacity the NREL estimates is available.

However, ninety-two US counties use power far in excess of what could ever be supplied locally by firmed solar. These are mainly populous, urban counties such as Los Angeles County, Harris County (Houston), Cook County (Chicago), and New York County, which covers the island of Manhattan. We estimate using the NREL solar supply curves data that there are 3 square kilometers of Manhattan that could, in theory, be turned over to solar power production (out of a total of fifty-nine). This would provide power for about 0.02 percent of Manhattan's demand. Clearly, populous urban counties will need to source their power from other places.

Figure 8. Local Land Requirements for Solar



Source: NREL; Global Solar Atlas; QCEW; Bureau of Economic Analysis; and authors' calculations.

Note: Data on local potential and land requirements are from the NREL estimates of developable capacity, in their reference case (Lopez and others 2024), combined with insolation data from the Global Solar Atlas. Local demand is estimated using the local county employment mix by industry from the QCEW, combined with sectoral electricity usage in the 2017 detailed input-output tables from the Bureau of Economic Analysis.

But how much long-distance transmission is actually required? In figure 8 we consider the amount of potential available in a broader local area: within 100 miles of the county centroid. We add up all the local developable solar potential, as well as all demand from counties within this radius, and then compute a measure of demand relative to potential within 100 miles. We plot this against the total land requirement of meeting demand. Now even the large urban counties (for the most part) are well able to meet their demand locally. Moreover, 94 percent of counties would require less than 5 percent of local land for power production, and in most cases significantly less.

While we make no prediction that autarky will be the actual outcome for many counties, this analysis does support the assumption that elastic entry is not severely challenged by local constraints on the availability of developable land for solar projects. As such, solar capital costs will create competitive pressure on wholesale generation in all parts of the United States. Meanwhile, the transmission network will remain crucial in ensuring access to low-cost supply from other areas, particularly for dense urban areas. We return to considering the build-out of the transmission network in section II.D.

II. The Macroeconomic Impacts of Lower Power Prices

Wholesale prices fall anywhere from 20 percent to 80 percent out to 2040, depending on the local solar resource, initial electricity costs, and local land costs. This is a large change in a key input price into production. How should we think about the impact of such changes on economic output?

Much recent work in economics has studied the pass-through from fundamental productivity and price shocks to final economic activity and welfare. Many considerations emerge, such as how the shocks affect market power, reallocation of factors across uses, and the direction of technical change (see Baqaee and Rubbo 2023 for a discussion of some of these issues). Here, we will keep our analysis relatively simple and focus on the regional exposure to energy price falls in general equilibrium. We conduct our analysis at the county level.

II.A. The Setup

Consider a spatial economy with locations ℓ and sectors s. Workers live in these locations (for example, Los Angeles County, or Yellowstone County in Montana) and choose a sector to work in (for example, aluminum smelting, finance, or hospitality). Firms produce and sell products within narrowly defined sectors, selling their products both locally and across the country. To produce, they need to hire labor, buy some intermediate inputs, and use some electricity.

We assume that firms produce a unique differentiated variety i. Firm i in location ℓ and sector s produces output according to the production function

$$y_i = z_i F_{\ell s}\left(l, e, X\right),$$

where l is labor, e is electricity, and X is an aggregator of a vector of intermediate sectoral inputs x. The variable z_i is an index of firm-level total factor productivity (TFP), as in Melitz (2003). Note that the production function $F_{\ell s}(\bullet)$ may be location- and sector-specific. This production function allows, for example, for exogenous local productivity differences as in Redding and Rossi-Hansberg (2017), and endogenous agglomeration forces that are location-sector specific as in Bartelme and others (2017), as long as these are taken as given by the firms.

Electricity is a local factor of production, with a price p_ℓ^ε. Labor has a price specific to the location and the sector, $w_{\ell s}$, arising from imperfect substitution across sectors within a location, and less than infinite elasticity of labor supply across space.

The exogenous productivity z_i is drawn from a distribution $\Psi_{\ell s}(z)$, which may depend on location or sector. Intermediate inputs enter through the aggregator in a symmetric way for all firms (though they may use this with different intensity) so that $X = f(x)$. We further assume that this aggregator takes the same form as the final good aggregator, so that both the intermediate price and the final good price serve as the numeraire.

Firms innovate a variety and enter the market by paying an entry cost, defined by $g_{\ell s}(l, e) = 1$, in terms of local labor and electricity. We assume g is constant returns to scale. The resulting entry cost is denoted $G_{\ell s}(w_{\ell s}, p_\ell^\varepsilon)$. Firms exit at an exogenous rate ξ.

Cost minimization for a given level of output y allows us to write a cost function

$$C_{\ell s}\left(y; w_{\ell s}, p_\ell^\varepsilon, z\right) = z^{-1} y v_{\ell s}\left(w_{\ell s}, p_\ell^\varepsilon\right),$$

where v is the average unit cost function for a location-sector pair.

We suppose the output market gives rise to a concave revenue function for the firm that takes the form

$$B_{\ell s}\left(y\right) = D_s r\left(y\right), \tag{4}$$

where $r(y)$ is continuously differentiable and concave, and where D_s is an aggregate sectoral demand shifter. This shifter is understood to be a fully endogenous object in general equilibrium and a function of all prices in the economy, but the firm takes it as given.[22] As we discuss in online appendix B, many demand systems have a revenue function that takes this form, including the classic constant elasticity of substitution (CES) demand system and single aggregator demand systems (see, for example, Arkolakis and others 2019; Matsuyama and Ushchev 2017).

So far we have not said much about the consumer side of the model, except the restrictions implied by equation (4), or how the investment costs to create firms are financed. In online appendix B, we discuss a general framework that will lead to this demand structure, as well as specifying how workers choose where to work and live, and a full dynamic structure for

22. Notice that this is not a completely innocuous assumption. For example, in our context it implies the absence of trade costs or differential wedges across location-sector pairs.

preferences. For now, all we require is that worker labor supply is increasing in the wage $w_{\ell s}$. Furthermore, different assumptions on the demand and market structure will result in a different form of the market shifter D_s. We make such assumptions explicit in section II.C and discuss how they allow us to solve for the general equilibrium of the model.

Without presenting and defining the full equilibrium structure for brevity (we do so in full in online appendix B), the key equilibrium condition we use for analysis is the free entry condition, which allows for an intuitive treatment of the local incidence of electricity price shocks. This ensures that discounted expected profit equals the entry cost and in a steady state takes the form

$$G\left(w_{\ell s}, p_\ell^{\varepsilon}\right) = \sum_{t=0}^{\infty} R_{0\to t}\left(\int_z \begin{bmatrix} \max_y D_s r\left(y\right) \\ - C_{\ell s}\left(y; w_{\ell s}, p_\ell^{\varepsilon}, z\right)\end{bmatrix} d\Psi_{\ell s}\left(z\right)\right). \tag{5}$$

where, as above, $R_{0\to t}$ is the cumulative interest rate.

II.B. Local Wage Responses to Changes in Electricity Prices

Let the local price of electricity be p_ℓ^{ε} in the long run. We use the bounds derived above in section I as an exogenous change in the local price of electricity driven by uptake of firmed solar power across the grid.

PROPOSITION 1. Assume that the free entry condition in equation (5) holds. Then the general equilibrium response of wages $w_{\ell s}$ in location ℓ and sector s in response to a local change to the price of electricity is given by

$$d\log w_{\ell s} = -\frac{\Phi_{\ell s}^E}{\Phi_{\ell s}^L} d\log p_\ell^{\varepsilon} + \left(\frac{\Phi_{\ell s}^E + \Phi_{\ell s}^L + \Phi_{\ell s}^X}{\Phi_{\ell s}^L}\right) d\log D_s, \tag{6}$$

where $\Phi_{\ell s}^E$ is total local sectoral expenditure on electricity, $\Phi_{\ell s}^L$ is expenditure on labor, and $\Phi_{\ell s}^X$ is total expenditure on intermediate inputs. The term $d\log D_s$ is a measure of sectoral demand changes as electricity prices fall across the country.

The intuition for this formula is simple.[23] Focus first on the term concerning $d\log p_\ell^{\varepsilon}$. If local costs of electricity fall, all else equal this causes local firms

23. A similar formula is derived in Eckert, Ganapati, and Walsh (2022) for declines in the investment price of capital, and the methodology derived there is the basis for our analysis here.

to become more profitable. In general equilibrium, this causes new firms to enter and incumbent firms to increase their labor demand and output, until that increase in profitability is eroded away by higher wages, and balance is restored. The strength of this effect is directly proportional to the intensity of electricity relative to labor in production. The intuition for the term $d \log D_s$ is similar. If aggregate sectoral demand increases (say, because of rising incomes) and firms are not competitive price takers, then firm-level profitability will again rise. This necessitates an increase in the cost of local labor to balance out the increase in profitability, and more so in places where labor is a smaller share of local sectoral input expenditure.

It is also worth stressing how general this result is, and thus how suitable for analyzing both the aggregate and distributional consequences of the transition to clean energy. To size the first term on the right-hand side of equation (6), we need to know nothing about elasticities of substitution between electricity and other inputs, either at the firm level or at the aggregate level. Indeed, so long as relationship in equation (4) is satisfied we do not need to know the details of any of the production functions. Importantly, we need no knowledge of firm-level heterogeneity or the firm size distribution.

Likewise, we need know nothing about labor supply elasticities or the ease of reallocating factors across firms to derive this expression. All we need is that labor is not perfectly mobile (or infinitely elastic) across space in response to wage changes, so that there is an upward-sloping labor supply curve for each region and for each sector. However, the shape of this curve is unimportant. Last, there is no requirement that the economy be efficient or close to an efficient equilibrium.[24]

Sizing the effect of the second term on local wages requires making further parametric restrictions, and we return to this in section II.C. The magnitude of the effect demands on a parameterization of aggregate demand externalities, which are common in models of monopolistic competition, and the exact details are model dependent. It is also worth noting that this term can be exactly zero in a model of competitive, price-taking firms with constant returns to scale production functions.

24. While this formula bears some superficial resemblance to Hulten's theorem and related results, it is quite distinct and arises from the basic requirement of zero expected profit after firm entry costs are paid. If firm production functions are constant returns to scale and markets are competitive, $d \log D_s = 0$ and only the first term on the right-hand side appears. A more general version with different factors is derived in Eckert, Ganapati, and Walsh (2022), from which we take inspiration here.

The nature of the exercise we undertake is to use the price bounds developed in section I to form an estimate of $d \log p^{\varepsilon}_{\ell}$, and then use equation (6) to trace through the general equilibrium impact on wages. We focus on wages first because of the excellent local data on sectoral employment and wages, available at very fine levels of geographic and sectoral disaggregation. Second, as long as the aggregate labor share is stable (or almost stable) and differences in goods prices across space are abstracted from, wage changes are a simple sufficient statistic for welfare.[25]

DIRECT REGIONAL EFFECTS While it is easy to derive the impact on local sectoral wages, estimating the impact on average wages in a location requires knowing how easy it is to reallocate labor across sectors. Let $\mu_{\ell s}$ be the employment share in sector s in location ℓ. We can write the change in average wages in location ℓ as

$$(7) \qquad d \log w_{\ell} = d \log \left(\sum_s \mu_{\ell s} w_{\ell s} \right) = \sum_s \frac{\mu_{\ell s} w_{ls}}{\sum_{s'} \mu_{\ell s'} w_{\ell s'}} \left(d \log w_{\ell s} + d \log \mu_{\ell s} \right).$$

Now suppose that we look at relatively fine industry classifications, so that no one industry is especially large. Furthermore, suppose that the long-run labor supply elasticity is the same across industries and constant at η (we provide a standard micro foundation in online appendix B). We then define a measure of exposure of local wages to the electricity price by combining equation (6) with equation (7) to obtain

$$(8) \qquad d \log w_{\ell} = \underbrace{\sum_s \frac{\mu_{\ell s} w_{ls}}{\sum_{s'} \mu_{\ell s'} w_{\ell s'}} \frac{\Phi^E_{\ell s}}{\Phi^L_{\ell s}}}_{\Omega_{\ell} \equiv \text{Direct Exposure}} d \log p^{\varepsilon}_{\ell} + \underbrace{\eta \sum_s \frac{\mu_{\ell s} w_{ls}}{\sum_{s'} \mu_{\ell s'} w_{\ell s'}} \left(\frac{\Phi^E_{\ell s}}{\Phi^L_{\ell s}} - \sum_{s'} \mu_{ls'} \frac{\Phi^E_{\ell s}}{\Phi^L_{\ell s}} \right)}_{\text{Labor Reallocation Across Sectors}} d \log p^{\varepsilon}_{\ell} + \underbrace{\Gamma_{\ell}}_{\text{G.E. term}}.$$

25. In the class of models we consider in online appendix B, with CES sectoral demand, firms' profits are proportional to sales. Thus, the only source of instability in factor shares comes from the aggregate elasticity of substitution between labor and energy. However, given energy's quantitatively small share, in practice this means the labor share of aggregate income is approximately stable.

We begin the quantitative analysis by examining wage growth induced by direct exposure. We calculate the direct exposure, Ω_l, at the county level. To get measures of local payroll and employment, we use the QCEW for 2023. We let s be a four-digit NAICS sector.

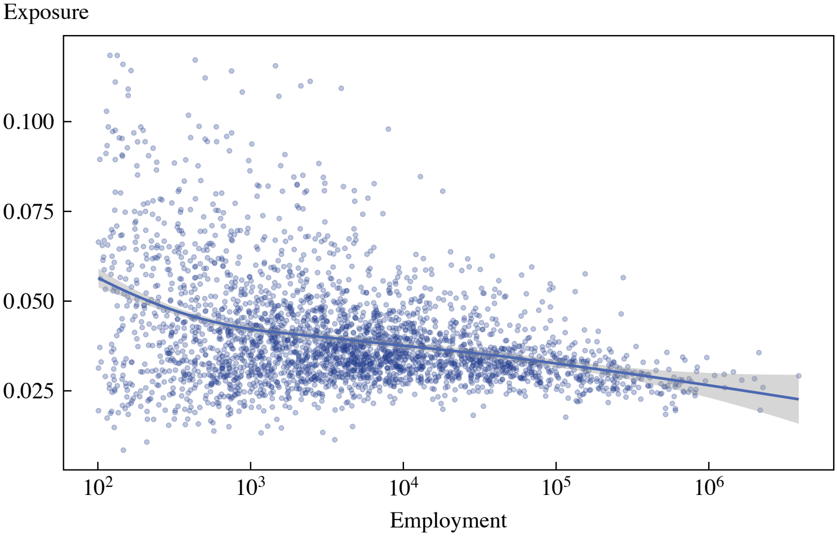
Electricity intensity is only measured well in a comprehensive way in the national input-output tables. For 392 four-digit industries, we construct the ratio of total sectoral expenditure on electric power generation, transmission, and distribution to total employee compensation, which measures $\frac{\Phi^E_{\ell s}}{\Phi^L_{\ell s}}$ at the sectoral level. We then do two imputations. First, we impute this ratio for missing industries via averaging the ratio (weighted by employment) at the three-digit level for the four-digit industries for which we have observations, and then applying this ratio to the missing four-digit industries. We repeat the procedure at the two-digit level for four-digit industries that have no other observations in their three-digit family. Second, we use the national-level industry ratios to proxy for the local-level ratios. We recognize that heterogeneity in local factor prices is likely to cause some measurement error here, but without better local data this is a good first step.

There is a large amount of heterogeneity in electricity intensity by detailed industry code. In online appendix A, table 1, we show the twenty-five most exposed industries. Far and away the biggest consumer of electricity is aluminum smelting, where the ratio of electricity payments to labor compensation is almost one for one. This is due to the energy-intensive nature of the electrolysis process, which converts alumina into aluminum useful for production. However, many other manufacturing and resource extraction industries, such as cement manufacturing, pulp mills, and metal mining, are also highly electricity intensive.

We then plot the direct exposure index Ω_l in figure 9 against area size as measured by employment. There is a clear negative correlation with population. This arises because electricity shares are lowest in service establishments, particularly in nontradable services like retail, hospitality, and education. In the data, there is a well-known strong correlation between population density and the percentage of employment in services, and this shows up in the ratio of payments to electricity to payments to wages inferred from the input-output tables. Large cities (employment above one million) have an average exposure of 0.026. This doubles in counties with population under ten thousand, due to their proportionally greater employment in manufacturing and resource extraction.

The labor reallocation term in equation (8) occurs when the average wage in an area shifts due to employment composition changing in response to

Figure 9. Direct Exposure to Electricity Price Falls

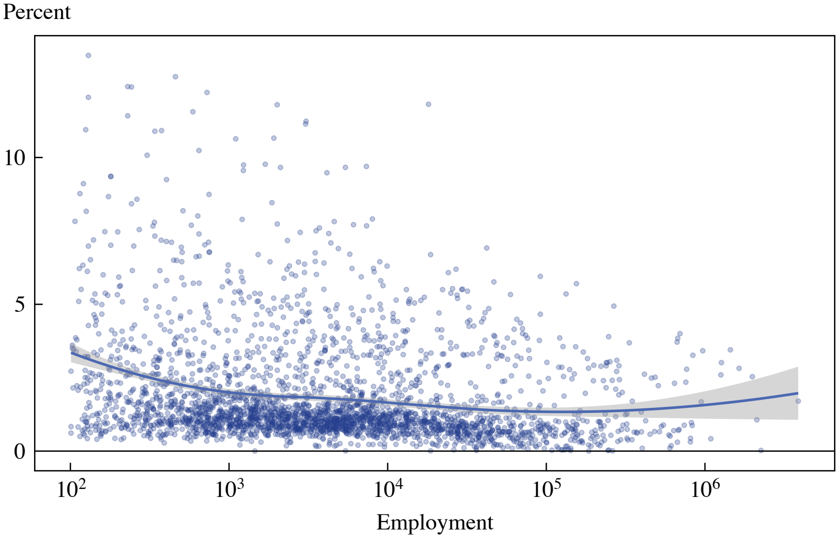


Source: QCEW and the Bureau of Economic Analysis's input-output tables for 2023.
Note: Figure shows the calculated direct exposure measures Ω_l from equation (8) at the county level.

industry-level wages moving. It is governed by the local labor supply elasticity η, which determines how labor moves between sectors in the short run in response to within-location wage changes.[26] Estimates in the literature tend to place this number around 0.2–0.7 (Artuç, Chaudhuri, and McLaren 2010). We will use the average elasticity for both college and noncollege workers estimated in Eckert, Ganapati, and Walsh (2022) (which one of us developed), and take a value of 0.5. We plot the resulting exposure terms with labor reallocation added against the original exposure terms in online appendix A, figure 24. Doing so has the effect of slightly muting the direct exposure in places that have less employment in exposed industries, since average wages in these less exposed industries (like business services) tend to be higher on average than wages in manufacturing. The opposite occurs in the more exposed areas. Overall though, for reasonable values of the labor supply elasticity this does not change the picture.

26. It is still the case that across-location labor supply elasticities have no bearing on the first-order wage change formula developed in equation (8).

Figure 10. Wage Changes from Direct Exposure



Source: QCEW and the Bureau of Economic Analysis's input-output tables for 2023.
Note: Figure shows the calculated direct exposure measures Ω_l from equation (8).

As such, areas with lower population density are, in theory, most exposed to the coming impacts of clean power. The actual changes, of course, will depend on the interaction of exposure with the falls in average prices, which are spatially heterogeneous.

In figure 10 we plot the county-level average wage changes implied by interacting the direct exposure and labor reallocation terms of equation (8) with the 2040 implied price falls from figure 22 in online appendix A. Projected wage changes differ markedly across space. As with exposure, there is a mild rural bias in wage growth. This stands in stark contrast to recent wage growth trends in the United States, which have overwhelmingly been urban-biased since 1980 (see Eckert, Ganapati, and Walsh 2022). Overall, the impacts from direct exposure are relatively modest: The average payroll-weighted real wage increase is 1.6 percent for the United States as a whole. However, there are several large cities and counties that see greater rises. Table 2 in online appendix A shows the top ten: Salt Lake City, Los Angeles, and Dallas all see real wage increases of almost 4 percent. This owes mostly to the fact that given their excellent solar insolation resources and high current power prices, they are projected to see substantial falls in wholesale power prices.

II.C. General Equilibrium Aggregate Demand Effects

In general equilibrium, there may be additional effects associated with aggregate demand expansion. In general, lower electricity costs will lead to greater output, which in turn raises demand for all the firms in the economy. To be consistent with free entry, wages will rise further than is implied by the direct impacts. As noted above, such effects do not appear in all types of models, which is why we began with the direct effects. In particular, if markets are fully competitive and production is constant returns to scale, as in a traditional analysis, then the effects estimated above are the true effects.

Let us continue to abstract from the role of intermediates and trade costs. We further assume that sectoral spending shares at the aggregate level are constant, and that firms face CES demand. In that case, we show in the online appendix that the change in the sectoral demand shifter firms face is simply given by

$$d \log D_s = d \log \Upsilon - d \log P_s^{1-\sigma_s}, \tag{9}$$

where Υ is aggregate income, and P_s is a sectoral specific price index, with σ_s being the elasticity of substitution across goods. The intuition is straightforward. When electricity prices fall, aggregate income rises (because of greater output). All else equal, this increases spending on firms' goods coming through $d \log \Upsilon$. Offsetting this is that greater aggregate output induces entrepreneurship and the entry of new firms, which create more competition for existing firms. This shows up in the sectoral price index, $d \log P_s^{1-\sigma_s}$, and acts to dampen firm-level demand. Deriving expressions for these two objects is relatively straightforward under standard assumptions on production functions.[27] We have

$$d \log \Upsilon = \sum_\ell \sum_s \frac{\sigma_s}{\sigma_s - 1} \frac{\left(w_{\ell s} L_{\ell s} + p_{\ell s}^{\varepsilon} E_{\ell s}\right)}{\Upsilon} \left(\begin{array}{l} \dfrac{\Phi_{\ell s}^{L}}{\Phi_{\ell s}^{L} + \Phi_{\ell s}^{E}} \left(\begin{array}{l} d \log w_{\ell s} \\ + d \log L_{\ell s} \end{array} \right) \\ + \dfrac{\Phi_{\ell s}^{E}}{\Phi_{\ell s}^{L} + \Phi_{\ell s}^{E}} \left(\begin{array}{l} d \log p_{\ell}^{\varepsilon} \\ + d \log E_{\ell s} \end{array} \right) \end{array} \right). \tag{10}$$

27. In particular, the production functions are constant returns to scale, and the costs to start a firm are denominated in units of the final good.

So the percentage change in aggregate income is just the activity-weighted change in local sectoral payroll and electricity sales.[28] It turns out that under the same assumptions

$$d \log P_s^{1-\sigma_s} = d \log \Upsilon_s - \frac{1}{\sigma_s}\sum_\ell \frac{w_{\ell s} L_{\ell s} + p_\ell^\varepsilon E_{\ell s}}{\gamma_s \Upsilon}\left(\frac{\Phi_{\ell s}^L}{\Phi_{\ell s}^L + \Phi_{\ell s}^E} d \log w_{\ell s} + \frac{\Phi_{\ell s}^E}{\Phi_{\ell s}^L + \Phi_{\ell s}^E} d \log p_\ell^\varepsilon\right),$$

where the change in sectoral income $d \log \Upsilon_s$ is analogous to equation (10). Then, as long as we have some notion of the elasticity of substitution across firms at the sectoral level σ_s, we can compute these terms given the data we've already outlined above.

Directly estimating sectoral elasticities of substitution is complicated and beyond the scope of this exercise. Many studies in the literature find values in the range of three to eight (see, for example, Hottman, Redding and Weinstein 2016; Gervais and Jensen 2019).[29] We will use a value of four across industries, which is common in models of consumer demand and firm dynamics (Garcia-Macia, Hsieh, and Klenow 2019; Peters and Walsh 2021). One can show that a higher value for σ dampens the general equilibrium effects, and in the limit as $\sigma \to \infty$ there is no aggregate effect of demand expansion. In addition, we will assume that the medium-run elasticity of demand for energy is around –0.5, consistent with estimates from the empirical literature (Labandeira, Labeaga, and López-Otero 2017).

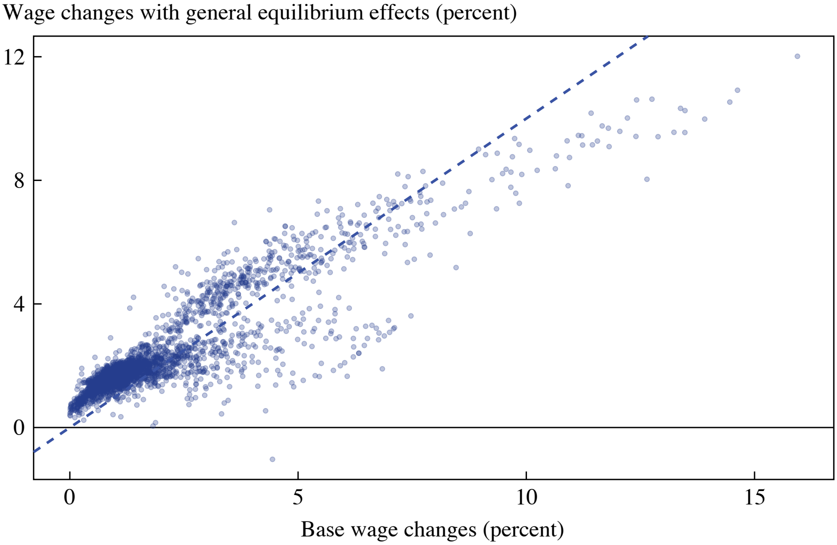
In figure 11 we show the county-level wage changes now including the general equilibrium effects. In general, these effects operate to dampen the wage changes of the most exposed places, as such places see more entry and firm creation (operating through $d \log P^{1-\sigma_s}$), which acts as a competitive spur to incumbent firms. As such, their profits increase by less than that implied by just the direct effect, and the local sectoral wage need not rise as much.

In contrast, places with low direct exposure see higher wage growth. This mainly comes from aggregate income rising as power prices fall, some of

28. This arises because of the fact that in models of CES demand with constant returns to scale production functions, profits are just proportional to sales, and so are also a constant fraction of expenditure on inputs.

29. Demand elasticities, which correspond to the elasticities of substitution here, can also be inferred from estimates of markups at the industry level, such as in Hall (2018), which would give numbers around four.

Figure 11. Wage Changes with General Equilibrium Effects



Source: QCEW; Bureau of Economic Analysis's input-output tables for 2023; and authors' calculations.
Note: Figure compares the county level wage changes from direct exposure with the wage changes including the general equilibrium effects computed from equation (9).

which then gets spent on low-exposure industries like personal services, food, and accommodation. One can think of the general equilibrium effects as redistributing the income gains from the most exposed places and sectors to the least. All in all, these effects are relatively modest and do not substantially change the conclusions of the initial analysis. The aggregate effect on national wages from transitioning to firmed solar power rises from 1.8 percent to 2.6 percent.

The heterogeneity in the local wage responses also matters for general equilibrium aggregation. For the change in aggregate income in equation (10), the positive covariance between local expenditure shares and local electricity price drops amplifies the general equilibrium rise in aggregate income. This would be missed by deriving an aggregate version of the free-entry equation without spatial and industry variation, which points to the importance of a disaggregated analysis for this question.

II.D. The Gains from Grid Integration

As we have emphasized, the spatial heterogeneity in price bounds presented in figure 6 will not represent the true heterogeneity in prices observed on a solar-dominated grid. While the free-entry condition implies an upper bound on prices, actual prices will be significantly below this bound in many areas. In particular, dense cities and suburbs, lacking cheap land for solar installations, will import much of their power consumption from surrounding areas using existing transmission infrastructure. The prices observed there will be closer to those seen in price nodes in rural areas, with adjustment for congestion.

The pricing formula used in many areas that implement locational marginal pricing is

$$p_\ell^\varepsilon = \underbrace{\varphi}_{\text{System Generation Cost}} + \varphi \underbrace{\frac{\partial L}{\partial D_\ell}}_{\text{Loss Adjustment}} + \underbrace{\sum_k z_k}_{\text{Transmission Constraints}}.[30]$$

That is, the price in an area depends on three components. First is the system generation cost, or the marginal cost of generation for the last unit that bids into supply within that area. Second is a term that adjusts this cost by the marginal impact on system units of an additional unit of demand D_ℓ for power in location ℓ. Last, for each transmission line k that connects to location ℓ, there is an addition to the price, which reflects whether that line is constrained and the effect of an additional unit of demand at ℓ on the load on line k.

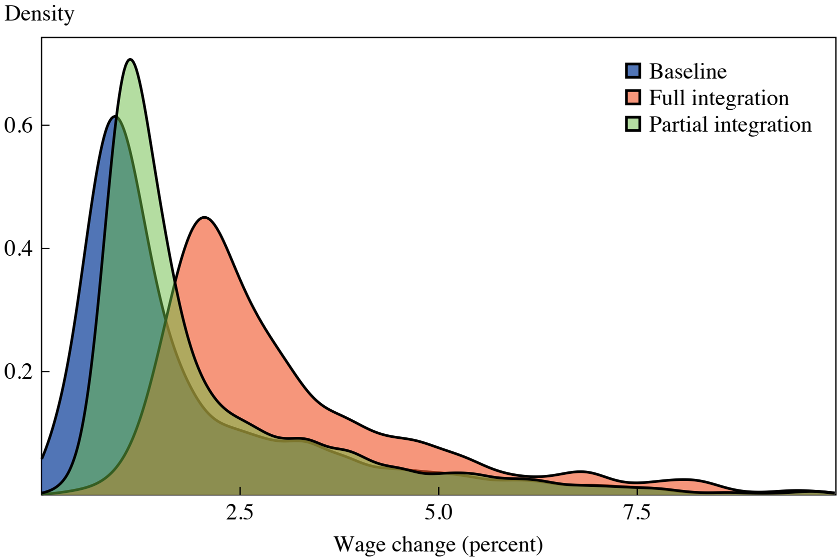
In a solar-dominated grid, the system generation cost φ will correspond to the average cost of generation of a unit of firmed solar power in the marginal areas connected to that independent system operator (ISO), as presented in equation (2).[31] For dense areas like New York County, which are unlikely to host solar farms within the city limits, the price of power will be determined by the generation cost in the rest of the (lower land cost) New York ISO, along with adjustments for congestion and transmission. As such, the true variation in prices in the future is likely to be lower than implied by figure 6.

But how much lower, and how costly is the resulting spatial heterogeneity in prices? Analyses of building out extra transmission capacity consider

30. See, for example, the New York Independent System Operator.

31. We deliberately say "average" here instead of "marginal" as the theory would imply. The marginal cost of generation of solar is effectively zero, and in an entirely solar-dominated grid the system generating cost must be the average cost of generation inclusive of capital cost for the most expensive solar unit, otherwise in the long run capacity would exit.

Figure 12. Gains from Grid Integration



Source: Authors' calculations.
Note: This figure shows estimates of the gains from grid integration in two scenarios: "Partial integration," where enough capacity is built for the price to fall to at least $25 per megawatt-hour at all points in space, and "Full integration," where price becomes uniform across the grid at the lowest price in the United States (around $17 per megawatt-hour). "Baseline" refers to the wage changes computed using only the price bounds from figure 6.

the effect of alleviating the congestion terms z_k, allowing high-cost areas to take advantage of lower and lower cost marginal generating units in other areas (and potentially other ISOs when considering interorganizational flows). Doing so is a complex endeavor, as it requires solving a high-dimensional nonlinear optimization problem. Here we come at the problem from a different angle.

The theoretical maximum increase in production in the medium term from transitioning to a clean grid would occur if all locations could access Arizona's generation cost of $17 per megawatt-hour. Such an integrated continental grid is likely to be technically infeasible, even with huge investment in interstate transmission. However, it does serve as a way to size the prize on offer.

In figure 12 we show the distribution across counties of the gains estimated using equation (8). For "Full integration," we recompute these gains if the implied price fall takes all locations to $17 per megawatt-hour. The economy-wide payroll-weighted average wage increase rises from 1.6 percent to 2.7 percent. In addition, almost 20 percent of counties now see a wage increase in excess of 5 percent, particularly counties in the industrial Midwest and New England. To put this in perspective, assuming a stable labor share, this implies an additional increase in GDP of $245 billion annually. To put it mildly, this is a large gain from a potential one-off investment.

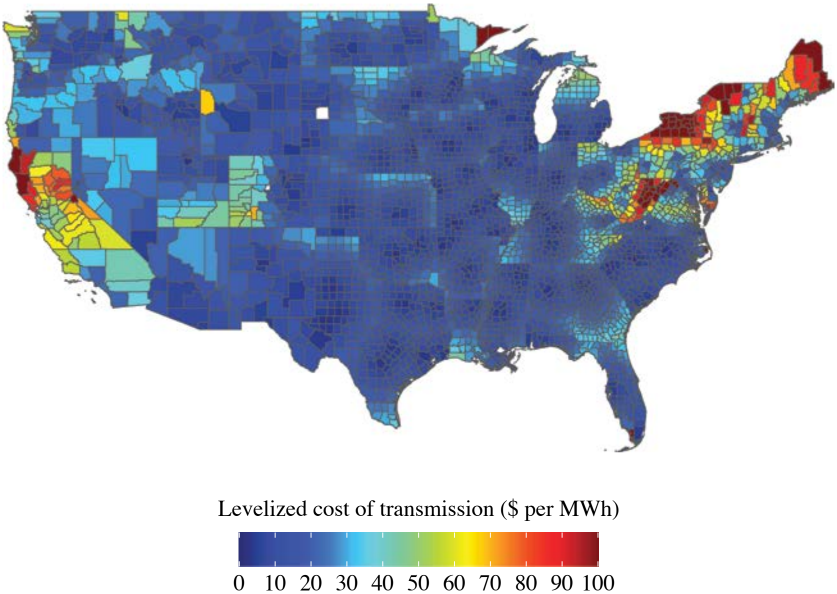
However, achieving this gain really does require that all locations have access to power costs that are only achievable in the West of the continent. If we consider a more mild integration, the gains are much more muted. Suppose that sufficient integration is achieved to take the maximum wholesale power price across the United States to $25 per megawatt-hour (around the median price in the analysis above, and near the minimum in the eastern half of the continent), and less if the implied local power prices are below this threshold. This is represented by "Partial integration" in figure 12. In this situation, the gains above the baseline are much more muted, rising from 1.6 percent to 1.9 percent in the aggregate. This suggests that the aggregate gains from harmonizing power prices in a renewable-dominated world may not be that large once solar determines the local price of generation. Further work on this topic is necessary.[32]

How costly is it for the Northeast to gain access to the lower wholesale costs in the center and West of the continent? This is a difficult question to answer at a system-wide level. Conceptually, there are two issues to consider. First, how costly is it for firmed solar projects to connect to the high-voltage transmission network locally, so that the electricity they produce can be sent long-distance across the country? Second, how much does the capacity of the system as a whole need to be upgraded to handle greater cross-regional flows?

While the second issue would seem to require a fully specified model of the US grid, for the first issue we can again use data from the NREL, which constructs localized estimates of the cost of connecting to transmission networks at fine geographic scale (Maclaurin and others 2021). This includes both the cost of building a "spur" connection from the solar site to the nearest substation on the electricity grid, as well as upgrading the

32. See Gonzales, Ito, and Reguant (2023) for an important real-world case study of the effects of building out transmission lines in Chile to connect high insolation areas with dense urban loads. The authors find significant reductions in electricity prices in the wholesale market as a result of grid integration and entry of renewables.

Figure 13. US Transmission Costs



Source: Maclaurin and others (2021).
Note: This figure shows average levelized cost of transmission at the county level.

substation and the local transmission network to handle the extra load.[33] In figure 13 we plot these data at the county level.

Several patterns are apparent. First, transmission and interconnection costs for solar are low in much of the country. In particular, the low generating costs areas of West Texas, New Mexico, Colorado, and Kansas also have very low costs of transmission, on the order of a few dollars per megawatt-hour. Particularly around established populations centers, these costs become negligible. Comparing with our results for the wholesale price bounds in figure 6, there are large swathes of the Southwest that can feed into the grid with both minimal transmission connection costs and low future wholesale prices. In contrast, connecting the quality solar resources

33. The first element is also counted in the BOS component of the analysis in section I, and as such we do not try to add the total levelized cost of transmission to our estimates of the capital cost in section I. The second component is difficult to conceptually allocate entirely to the solar project developer, since network upgrades additionally benefit all other local projects and end consumers.

of California to the grid appears to be quite costly. According to NREL, these differences are driven by regional construction cost multipliers for California and the Northeast, which drive up the cost of construction relative to the rest of the country. Permitting and environmental approvals are particular levers that could be examined to reduce these costs.

An additional concern is the effect of time delays in the interconnection queue, which is a common complaint of renewable project developers in 2024. The Lawrence Berkeley National Laboratory estimates that there are 2.6 TW of new capacity proposals waiting in the queue to receive approval to connect to the grid (Rand and others 2024). Over 80 percent of these requests are solar, battery storage, or hybrid plants with both solar and storage. Depending on the region, getting approval often involves simulation studies of the effect of the project on local power flows and reliability. A key issue with renewable interconnections is that because of their smaller average sizes than the fossil fuel projects of the past, connecting renewable projects to the grid in tandem requires a greater number of reliability studies, which appears to be significantly slowing approvals. Projects are now waiting up to five years to receive approval, up from two years in 2008 (Rand and others 2024).

At one level, in our framework this is a transitional issue. Shifting the expected revenues even five years ahead into the future in equation (2) has a quantitatively small impact on the wholesale price bound for 2040, given relatively low prevailing interest rates. Through this lens, it has little impact on the macroeconomic impacts of clean power. At another level, however, increasing the expected wait time before interconnection can significantly increase risk for a project: risk of financing challenges, risk of regulatory changes, and risk of development objections, to name a few. Project risk is not adequately captured by our framework. Nonetheless, it seems clear that such long lead times for interconnection are not necessary and are a result of processes that could be streamlined. The Electric Reliability Council of Texas (ERCOT), for example, processes interconnection requests within eighteen to thirty months, much faster than the median wait time of five years in 2023 outside ERCOT (Fernandes 2024).

II.E. Pass-Through

When we consider the effect of declines in power prices on real wage growth, we are assuming a one-to-one long-run pass-through from wholesale to retail prices, which is unlikely to be the case in reality. According to the EIA (2023), average US retail prices break down into 62 percent generation costs, 12 percent transmission costs (the cost of moving electricity down high-voltage transmission corridors), and 26 percent distribution costs (delivery to the final end user). While large industrial users typically pay close to wholesale generation prices, since their steady load and higher-voltage requirements limit the need for distribution infrastructure, residential users and smaller commercial users typically pay higher costs that include distribution charges as a markup on the wholesale cost of supply. Our arguments above mainly concern lowering generation costs; technical scope for reducing transmission and distribution costs seems more limited. However, it is worth making two brief points before concluding.

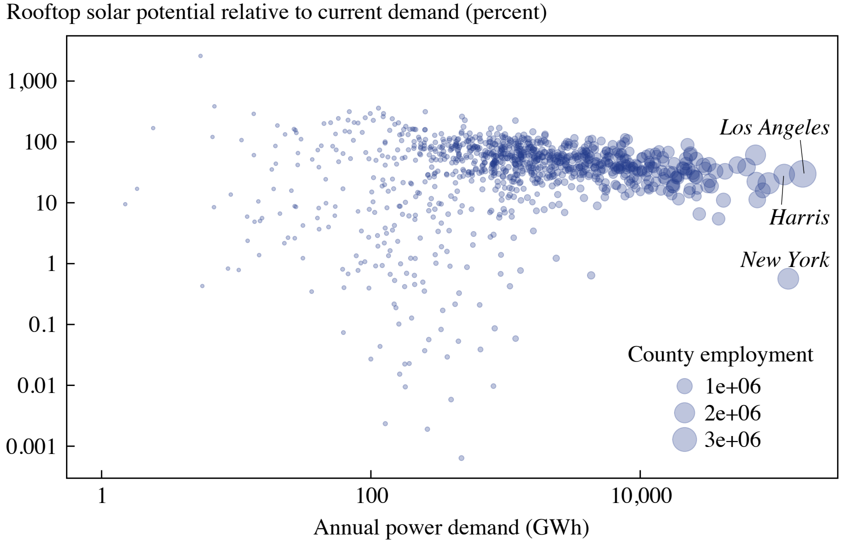
Much of the pricing model of regulated distribution networks reflects monopoly rents to cover the cost of distribution assets that have been fully depreciated. Many regulated utilities in the United States (for example, Pacific Gas and Electric Company operating under the California Public Utilities Commission) operate via making a case to a government regulator for a "revenue requirement," to cover the cost of owning and maintaining the distribution network, along with a regulated rate of return on their fixed asset base. This determines the markup on average wholesale power prices that they charge to the end user. It almost goes without saying that this is not a pricing model that has historically encouraged efficient investment.

There has historically been no way for commercial and residential consumers to avoid joining these networks, as they act as natural monopolies. The arrival of modular rooftop solar with cheap storage changes this picture. Residential and commercial adoption of firmed solar power is likely to act as a competitive spur to regulated distribution monopolies in a way that may encourage lower residential markups. While we may never see mass grid defection, with large numbers of users disconnecting from the grid altogether, the arrival of competition at the end use is a separate source of pressure on electricity prices, distinct from the lowering of wholesale generation costs.

Indeed, there is a large enough amount of rooftop solar potential in many counties to make this competitive possibility a threat to the distribution monopolies. In figure 14 we use data from Google's Project Sunroof to form an estimate of the potential production of electricity on a county's roofs and show this relative to our estimate of current county demand.[34] In almost all counties for which we have data, rooftop potential ranges between 10 and 100 percent of current county demand. A notable exception

34. Project Sunroof, "Data Explorer," Google, https://sunroof.withgoogle.com/data-explorer/.

Figure 14. Rooftop Solar Potential



Source: Google's Project Sunroof and authors' calculations.
Note: Figure shows an estimate of rooftop solar potential at the county level from Google's Project Sunroof against our estimate of county demand. County estimates are missing in the Project Sunroof data for 2,103 counties.

is Manhattan, with its unparalleled density of skyscrapers having little relative roof space.

So far, rooftop solar uptake has been slow in the United States, given the dramatic cost falls in the price of panels that have driven utility-scale solar energy. NREL puts the cost of deploying residential solar in 2023 at more than twice the cost per kilowatt of utility-scale solar energy. Partly this is due to higher labor installation costs when the scale economies of utility installation are absent. However, the greatest difference in cost comes from the soft costs of permitting and getting approval for the panels, which made up 54 percent of the total cost in 2023 (Ramasamy and others 2023). This cost wedge is by no means an immutable fact of life: Australia, with insolation and incomes similar to California and Texas, now has solar panels on one-third of the country's roofs, generating 12 percent of the country's electricity supply in 2024 (Minister's Office 2024).[35] Notably, installation costs are much lower than in the United States, while the modules and

35. Open Electricity, https://explore.openelectricity.org.au/energy/nem/?range=all&interval=1y&view=discrete-time&group=Detailed.

equipment in both countries are common. This suggests that state- and city-level permitting reform to streamline installation processes could yield large benefits, not only by directly lowering solar costs, but also by placing competitive pressure on distribution monopolies for the first time since the early days of the electricity grid.

II.F. Electrification

Our analysis makes no prediction about the quantities of electricity supplied by renewables; it is entirely price-based, which is both a strength and a weakness. As such, it is ill suited to consider an increasing share of electricity in final production, which would have implications for the welfare impact of moving to clean energy. A big part of decarbonization efforts will involve electrifying significant parts of the economy. This includes shifting the transportation sector to primarily electric vehicles (a shift that is well underway worldwide) and moving building heat from oil and gas to electricity. NREL projects that electrification could increase US electricity demand, which has been flat for decades, by between 20 and 38 percent (Mai and others 2018). In addition, new sources of demand may further increase demand for electricity and its share in final production. The Department of Energy, for example, projects with increasing demand for electricity from data centers, including artificial intelligence servers, could consume as much as 12 percent of the country's electricity supply, up from 4 percent now (Kearney 2024).

A 20–40 percent increase in electricity output may not be associated with a significant increase in the electricity share Φ^E, especially as this analysis predicts that electricity prices fall by between 20–80 percent. The exact details will be location and industry specific in a way that is difficult to know before the fact. However, to the extent that the electricity share of final value added is set to increase in a clean future, the welfare analysis in this section understates the true real wage gains from moving to a clean energy future.

III. Beyond the Medium Term: Removing Energy's Drag on Growth?

So the medium-term impacts of the transition to clean power are likely to be relatively modest wage increases, with a moderate rural bias. Going beyond first order could take us into considering reallocation of factors across industries and space to more energy-intensive sectors and to cheaper power locations.

However, there is another dimension in which the replacement of fossil fuel energy with clean technology based on manufactured goods represents a qualitative change in the structure of the economy. What the replacement of fossil fuels with clean electricity really does in the long run is turn energy from a problem of *finite resource extraction* to *capital accumulation*. This has significant implications for the direction of innovation at the aggregate level.

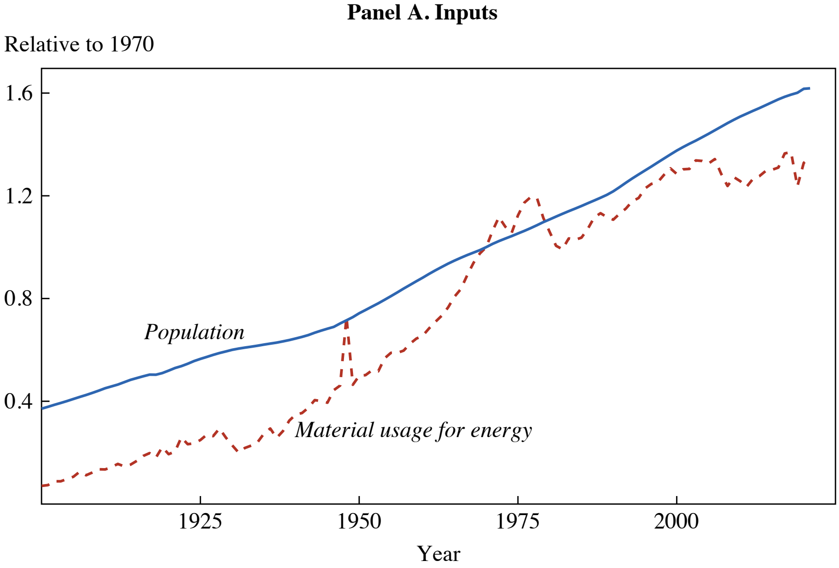
A number of analyses have pointed out that a structural shift occurred in the United States around 1970 related to energy use. Energy inputs from three primary sources—petroleum, coal, and natural gas—had been growing strongly for decades. At the same time, prices for these inputs remained relatively stable in real terms. Then, with the Arab oil embargo, the price of these inputs shot up, as can be seen in figure 15. In subsequent years, these prices have stayed high, and have even been increasing on average relative to the pre-1970 period (though with considerable volatility). At the same time, energy usage has grown slower than population, a dramatic reversal from the pre-1970 pattern. As a result, energy intensity (in terms of joules per dollar of GDP) has been falling for many decades.

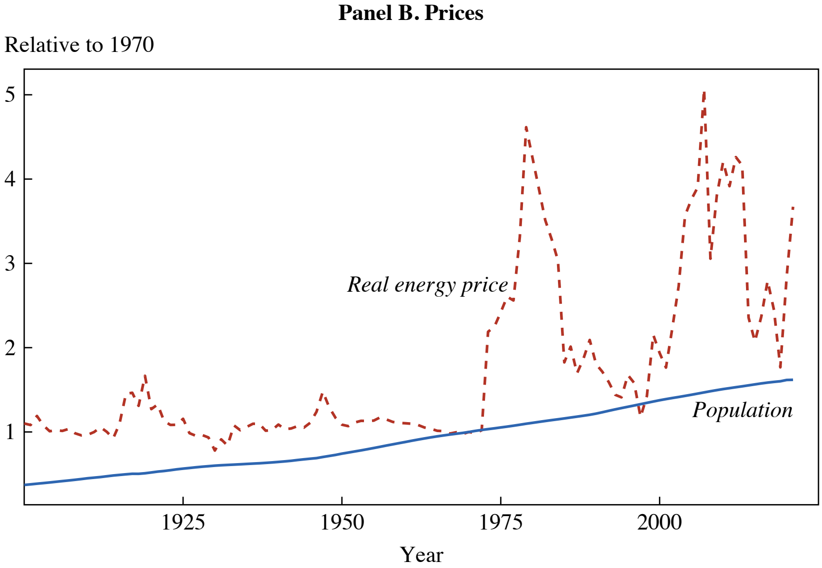
Hassler, Krusell, and Olovsson (2021) show that this has been achieved through significant directed technical change in energy usage, with the productivity of energy usage in particular tripling since 1970 (after being roughly constant beforehand). It is easy to think of examples of greater energy efficiency in everyday life. Fuel economy for vehicles has risen dramatically, lighting with LEDs uses an order of magnitude less electricity than incandescent bulbs, and household appliances like refrigerators and air conditioners consume much less power than their counterparts from 1980 and 1990.

These efficiency gains did not fall like manna from heaven; they were achieved through the purposeful use of innovative inputs like scientific labor and firm research and development (R&D) spending. Given that at any point in time, resources available for innovation are limited in the aggregate, this implies a trade-off between energy-specific innovation and other forms of innovation. Indeed, this shift in the direction of aggregate innovation may partly explain the relatively slow labor productivity growth observed since 1970. Nordhaus (2004) traces the sectoral propagation of the productivity slowdown in the 1970s and shows that it was concentrated in the most energy-intensive sectors (see also Nordhaus 1992 for a broader discussion of the "resource drag").

The need to combat rising energy prices through greater energy efficiency investment acts as a drag on aggregate income growth. This drag can be

Figure 15. Energy Inputs and Prices





Source: For panel A, the data from 1949 onward are from EIA and the pre-1949 data are digitized from Potter and Christy (1962). Data in panel B are from the Bureau of Labor Statistics and authors' calculations.

Note: Panel A shows an index of total petroleum, coal, and natural gas usage in the US economy against US population. Both index and population are shown relative to 1970. Panel B constructs a Törnqvist price index for these commodities, divides this index by the consumer price index for urban consumers (CPI-U), and normalizes the resulting series relative to 1970.

completely eliminated in a world where energy production arises from capital accumulation instead of extraction of a scarce input. To see why, we compare the Hassler, Krusell, and Olovsson (2021) model of endogenous growth in an environment of resource scarcity with the same model in an environment where energy can be produced by accumulating renewable capital.

In the Hassler, Krusell, and Olovsson (2021) model, there is a fixed amount of innovative resources that can be directed at improving productivity of either a capital and labor bundle or energy inputs, both of which are needed to produce output. In most other respects, it is identical to the optimal growth model: Capital can be accumulated, and the representative agent is maximizing intertemporal utility but choosing savings, consumption, and the allocation of innovative resources.

We present the model in the left column below.

Growth with Resources

$$\max_{c_t, k_{t+1}, e_t, n_t \in [0,1]} \sum_{t=0} \beta^t \frac{c_t^{1-\sigma}}{1-\sigma},$$

subject to

$$c_t + k_{t+1} = F\left(A_t k_t^{\alpha}, A_{et} e_t\right) + \left(1-\delta\right)k_t,$$

and

$$\frac{A_{t+1}}{A_t} = f\left(n_t\right) \quad \frac{A_{et+1}}{A_{et}} = f_e\left(1-n_t\right),$$

and where resources e_t are finite, so

$$\textstyle\sum_{t=0}^{\infty} e_t = E_0.$$

Growth with Renewables

$$\max_{c_t, k_{t+1}, k_{Rt+1}, n_t \in [0,1]} \sum_{t=0} \beta^t \frac{c_t^{1-\sigma}}{1-\sigma},$$

subject to

$$c_t + k_{t+1} + k_{Rt+1} = F\left(A_t k_t^{\alpha}, A_{et}\left(\theta k_{Rt}\right)\right) + \left(1-\delta\right)k_t + \left(1-\delta_R\right)k_{Rt},$$

and

$$\frac{A_{t+1}}{A_t} = f\left(n_t\right) \quad \frac{A_{et+1}}{A_{et}} = f_e\left(1-n_t\right).$$

The notation is standard, but briefly, c_t is consumption, k_t is capital per worker, e_t is energy inputs (meant to represent exhaustible fossil fuels), A_t is factor-augmenting technical change, and A_{et} is energy-augmenting technical change. The term n_t is innovative resources that can be directed either at improving factor-augmenting productivity A_t or energy productivity A_{et}.

Importantly, energy inputs are in finite supply. Without innovation in how productive these inputs are, and similarly no innovation in capital and labor productivity, this is akin to the classic cake-eating problem that is used to teach dynamic optimization, and our diminishing supply of finite resources causes consumption to diminish over time. This is also one way to think about a model of "degrowth," as advocated by Hickel (2021) and others.

Even with continued growth in factor-augmenting productivity A_t, it is not a given that growth in consumption is possible in the long run without growth in A_{et} when resources are in finite supply. As pointed out by Solow (1974) and Stiglitz (1980), if the elasticity of substitution is greater than or equal to one, either in a CES formulation or asymptotically for $F(\cdot)$ as $e \to 0$, then growth in the long run is possible. Greater technical progress and accumulation of capital can offset the diminishing supply of energy. If, however, energy and production factors are global complements, then the long-run path for the global economy features falling resource use, falling consumption, and a rising resource share.

In the formulation of Hassler, Krusell, and Olovsson (2021), innovation can be directed toward improving energy efficiency, which alleviates this restriction. No matter the elasticity of substitution, we escape the curse of finite resources. The balanced growth path solution involves resource use falling at the constant rate $\beta g^{1-\sigma}$, where g is the growth rate of output, and an ever-rising shadow price for the resource as it is used up.[36] Innovation is positive in both factor-augmenting productivity A_t and energy productivity A_{et}, and innovative resources are directed to both sectors. However, resources are still a drag on aggregate growth.

In the right-hand column above, we modify the economy so that energy is instead produced by capital. Recall that the first two fundamental features of renewables we discussed at the start of this paper were that they were modular (so that power output is a linear function of capital installed), and that they had zero resource cost. As such, we substitute exhaustible fossil fuel inputs e_t for renewable capital k_{Rt}, which produces energy at rate θ (as in the analysis of the preceding section). We'll also assume for simplicity that there are no exhaustible resources used in the production of renewable capital, silicon and iron being in such abundance in the earth's crust that they are not worth modeling.

One can show that the balanced growth path in this economy looks quite different. With this small modification, there is no long-run improvement

36. Decentralizing this economy can be done in a straightforward way by modeling the incentives of private firms to invest in the two kinds of technical change. Of course, there is no guarantee that the competitive economy is efficient.

in energy efficiency, and all innovative resources are deployed to factor-augmenting technical change. In a sense, renewables remove the scarcity of fossil fuels, as energy produced is limited by the amount of capital that can be accumulated, not by how much of a finite resource can be extracted.[37] The long-run growth in output g is also strictly higher than that in Hassler, Krusell, and Olovsson (2021) as shown in the left-hand column.

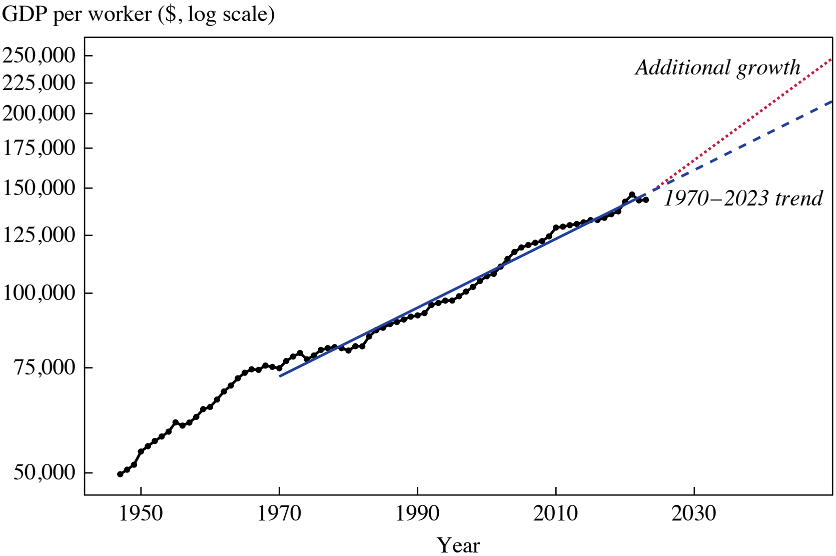
This result is reminiscent of the celebrated Uzawa (1961) theorem, in which all technical progress in the long run must be labor augmenting (see Jones and Scrimgeour 2008 for a discussion). The basic intuition of the Uzawa theorem is that because capital is accumulated and labor is not, the trend in capital inherits the trend in total output. "Effective inputs" have to grow at the same rate for factor shares to be stable, so effective capital (capital multiplied by capital-augmenting productivity) has to grow at the rate of effective labor (labor multiplied by labor-augmenting productivity). Because capital alone is growing at the rate of output, effective capital must also be, and this has to be equal to the growth rate of labor-augmenting productivity.

Something similar happens here. For long-run factor shares to be stable, $A_t k_t^{\alpha}$ and $A_{et}\theta k_{Rt}$ have to grow at the same rate. But balanced investment requires renewable k_{Rt} and production investment k_t to grow at the same rate, and both to grow at the rate of output g_y, since $F(\bullet)$ is constant returns to scale. Then $g_y = g_A + \alpha g_y = g_{Ae} + g_y$ implies that $g_{Ae} = 0$. Put another way, when energy comes from accumulated capital—and, as would be the case with firmed solar, total energy is linear in the amount of capital installed—stable growth in the long run requires that energy efficiency stop improving. All innovative resources are directed at capital and labor alone. This argument can be made rigorous in a decentralized world.

Such a shift in the growth pattern could have quantitative bite. The estimates of Hassler, Krusell, and Olovsson (2021) imply that for $g_{Ae} = 0$, the frontier for TFP growth g_A could rise from 1 percent to 1.2–1.4 percent, a significant improvement on what we have seen in recent decades. The possibilities of such an improvement are tantalizing. In figure 16 we show the difference such an uptick makes in GDP per worker over the subsequent decades. By 2040, GDP per worker is 5–10.5 percent higher

37. Given our discussion of land requirements for solar above, it is worth noting that it is not strictly true that there is no resource requirement for renewables. The quantity of land is, after all, finite and places a ceiling on the amount of renewables that may be installed. However, given how much solar potential there is relative to current US power demand, we believe this ceiling is comfortably high enough for this to be a meaningful abstraction.

Figure 16. Removing the Resource Drag



Source: Bureau of Economic Analysis; Hassler, Krusell, and Olovsson (2021); and authors' calculations.
Note: This figure shows real GDP per worker from 1947 to 2023 in 2017 chained dollars from the Bureau of Economic Analysis (beaded line). The dashed line projects the series out to 2050 using the 1970–2023 average growth rate. The dotted line uses the estimates from Hassler, Krusell, and Olovsson (2021) to derive an estimate of additional growth that would result from replacing fossil fuels with renewable capital in the aggregate production function.

without the drag of finite resources for energy. While more speculative, this is more than double the gains from cheaper power studied above. It is worth emphasizing that the two macroeconomic effects of clean power are distinct. The first thing renewables do is make electricity cheaper in the medium run, an effect that is almost baked in at this point. The second thing they might do is free up innovative resources in the aggregate to better improve capital and labor productivity.

ACKNOWLEDGMENTS We thank our editors Jón Steinsson and Janice Eberly, as well as our discussants Neil Mehrotra and Koichiro Ito for their excellent comments. Cheolhwan Kim, Pablo Mones, Eshaan Patel, and Yirui Zhao provided outstanding research assistance. We would also like to thank Lucas Epstein for various comments. The authors would like to acknowledge the support of National Science Foundation under grant SES-2117288.

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Comments and Discussion

COMMENT BY

KOICHIRO ITO Effective and economical expansion of renewable energy is one of the most urgent and important challenges in addressing climate change. The electricity sector generates one of the largest shares of global greenhouse gas emissions, alongside the transportation sector.[1] Furthermore, a significant portion of the transportation sector is expected to be electrified in the near future, making decarbonizing electricity generation critical to addressing climate change.

Until recently, large-scale expansion of renewable energy was considered impractical for at least three reasons. First, the levelized cost of energy (LCOE) for renewables, especially solar power, was significantly higher than that of other technologies such as thermal, nuclear, and hydropower. However, the LCOE for renewables has fallen dramatically. Data from Davis, Hausman, and Rose (2023) show that the LCOE for solar was near $500 per megawatt-hour in 2010, declining to $36 per megawatt-hour by 2022. In 2022, the LCOE for combined-cycle natural gas and wind was $37 and $38, respectively, indicating that these three technologies now have comparable costs.

Second, the best locations for renewable energy production tend to be in remote regions such as deserts and mountains, far from major electricity demand centers such as cities and industrial hubs. Many countries have

1. Electricity and heat production account for 25 percent of the 2010 global greenhouse gas emissions and transportation accounts for 14 percent (IPCC 2014). In the United States, 29 percent of the greenhouse gas emissions in 2019 came from the transportation sector, and 25 percent came from the electricity sector (US Environmental Protection Agency 2021).

Brookings Papers on Economic Activity, Fall 2024: 213–238

recognized this disconnect as a critical issue and have begun addressing it by developing integrated markets with high-capacity transmission lines (Gonzales, Ito, and Reguant 2023).

The third challenge, particularly relevant to this paper by Arkolakis and Walsh, is the intermittency of renewable energy production. Solar and wind depend on weather conditions and time of day, leading to fluctuations in electricity generation. While it has been clear that electricity storage can mitigate this issue, the high cost of large-scale batteries has made this solution economically unfeasible, keeping intermittency a major challenge.

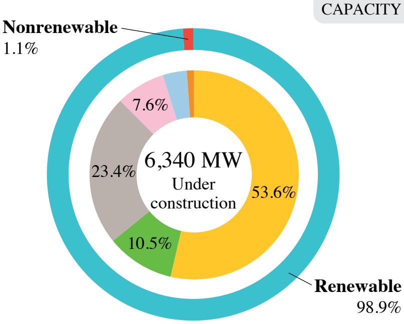
One of the key contributions of Arkolakis and Walsh is their forward-looking approach to the potential availability of large-scale battery capacity. Based on historical battery price trends, they use a forecast that the battery price will fall to $20 per kilowatt-hour by 2040. At this price, solar and wind power plants could be paired with sufficient battery storage to continuously supply electricity to the grid without intermittency. This forward-looking perspective is useful for forecasting electricity markets in the future. While the pace at which battery prices will decline remains uncertain, as I will discuss below, the authors' framework provides a useful guide for envisioning a future scenario in which battery storage might resolve renewable intermittency.

Another important innovation of this paper is the authors' simple method for forecasting future wholesale electricity prices in US regions, based on equation (2) of their study. In the literature on wholesale electricity markets, the standard approach involves quantifying locational marginal prices using data on demand, supply, and grid congestion as well as market clearing mechanisms with a variety of constraints such as congestion in transmission lines. The advantage of the authors' method is that it does not require intensive data collection and modeling the details of market clearing process. They instead rely on a medium-run equilibrium condition, where the cost of marginal solar and wind power investment equals the net present value of future profits from that investment. Conceptually, this approach is similar to the solar investment model in Gonzales, Ito, and Reguant (2023). Arkolakis and Walsh's novel approach is to use this equilibrium concept to forecast locational marginal prices across all US regions. While their method is not without assumptions and does not predict electricity quantity, it offers a valuable complementary approach to traditional wholesale electricity market models.

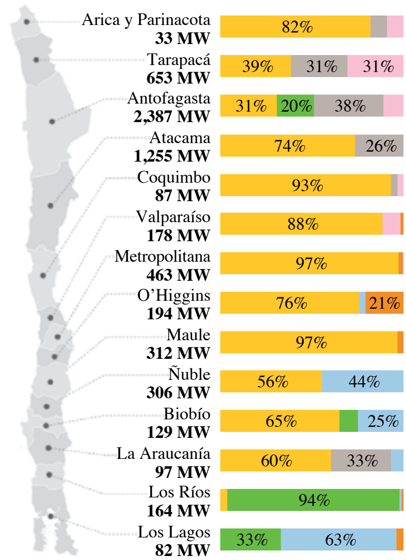
The authors' findings suggest an optimistic outlook for renewable energy expansion in the United States. By 2040, power prices in the country could fall between 20 percent and 80 percent, driven by market forces rather than

Figure 1. List of New Power Plants Under Construction in Chile in August 2024

NES CAPACITY | **REGIONAL** CAPACITY



Technology	Capacity (MW)	No. projects	% Total
Solar PV	3,400	262	53.6%
Wind	666	11	10.5%
BESS	1,483	16	23.4%
PV + BESS	485	6	7.6%
Hydro RoR	236	12	3.7%
Total	**6,269**	**307**	**98.9%**
Oil	68	10	1.1%
Natural Gas	3	1	0.0%
Nonrenewable	**71**	**11**	**1.1%**
Total	**6,340**	**318**	**100.0%**



Source: Reproduced from Generadoras de Chile (2024) with permission.

Note: This figure shows the list of new power plants under construction in Chile as of August 2024. The table shows new power plants under construction by technology. The map shows the capacity of new power plants under construction by technology and region covered by the National Electric System (NES).

*PV: photovoltaic; RoR: run-of-river; BESS: battery energy storage system (standalone and hybrid projects); PV + BESS: considers the solar component; MW: megawatt.

government interventions. This reduction in electricity prices, in turn, is projected to lead to a 2–3 percent real wage gain for US workers.

The question is whether this is an overly optimistic scenario, or could these results materialize by 2040.

On one hand, this scenario is already unfolding in some countries, including Chile. Figure 1 shows the list of new power plants under construction in Chile as of August 2024 (Generadoras de Chile 2024). The top four technologies include solar photovoltaic (53.6 percent), batteries (23.4 percent), wind (10.5 percent), and solar plus batteries (7.6 percent). In this sense, the future scenario envisioned by Arkolakis and Walsh is already becoming a reality in Chile.

On the other hand, there are reasons to be cautious about applying this scenario to the United States. Three key challenges may make the authors' forecast potentially overly optimistic for the United States.

First, the affordability of large-scale batteries within the next fifteen years is uncertain. While it is widely expected that solar and wind costs will continue to decline, long-term forecasts for battery prices remain contested. As shown in figure 4 in their paper, some studies predict sharp declines in battery prices, fueled by increased demand for electric vehicles and advancements in battery research. However, other studies anticipate a more gradual decrease. Given that the affordability of large-scale batteries is central to the authors' model, the uncertainty around battery price trends needs to be carefully considered.

Second, the feasibility of building the necessary long-distance, high-capacity transmission lines in the United States remains uncertain. As summarized by Cicala (2021), the United States faces significant challenges in this area. The Federal Energy Regulatory Commission (FERC), which oversees transmission development, has less authority than its counterparts in other countries, particularly regarding interstate long-distance lines. Moreover, a key renewable-rich market, the Electric Reliability Council of Texas, falls outside the FERC's jurisdiction, complicating efforts to connect Texas to the broader US grid.

For this reason, the analysis in section II.D. of the paper, which explores various grid integration scenarios, is particularly relevant. The regulatory challenges may limit the extent of grid integration by 2040, and therefore, their baseline scenario—the scenario where there is limited grid integration—might be most relevant to the reality. Yet, their analysis of partial and full integration scenarios also provides useful insights into the potential benefits of further grid integration.

Third, the United States faces a regulatory bottleneck known as the "interconnection queue" problem. Many renewable power plants are currently waiting for approval to connect to the grid, with the median wait time now extending to five years as of 2023 (Rand and others 2024). This delay is due to a slow-moving regulatory process, and while the FERC and other market operators are working to address the issue, it remains a significant source of uncertainty for renewable energy projects. As of 2023, around 2,600 gigawatts of capacity—more than twice the size of the entire US power plant fleet—was waiting in the queue (Rand and others 2024). This backlog is likely to delay the pace of renewable investments and could impact the forecasts of renewable expansion in this paper.

These three challenges—battery affordability, transmission development, and the interconnection queue—suggest that while the authors' optimistic forecast is a valuable and innovative contribution, it may need to be interpreted with caution. This is not because of their analysis per se, but because of technological and regulatory uncertainty in the three points mentioned above. Nevertheless, their work is an important step forward, and the insights they provide will be key to future research and policy discussions on renewable energy expansion.

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US Environmental Protection Agency. 2021. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2019*. Washington: US Environmental Protection Agency.

COMMENT BY

NEIL R. MEHROTRA The plunging price in renewable energy technologies—particularly solar panels and batteries—has the potential to revolutionize power production in the coming decades. Arkolakis and Walsh document the decline in prices for solar power and batteries and consider the economic implications for electric power prices, wages, and growth in the United States. The authors consider both nationwide and regional implications for prices and wages, finding a 20–80 percent decline in wholesale electricity prices by 2040 and wage gains up to 3 percent in some locations. The authors also provide a more speculative estimate of how energy abundance from cheap renewables may raise long-run productivity growth in the United States.

In this paper and their companion paper (Arkolakis and Walsh 2023), the authors make a compelling case that falling prices for renewable energy will have profound implications on energy markets and economic growth. In this discussion, I will argue that the authors' estimates of price declines for wholesale electricity prices are likely overstated even taking as given their projections for falling technology costs. The key issue limiting the fall in electricity prices is the additional backup power generation and storage required to "firm" the intermittent production from renewables. I will reference results from the energy systems literature, establish how the system cost of electricity differs from the levelized cost concept used in the paper, and document the continued rise in the US wholesale electricity prices despite declines in generation and fuel costs.

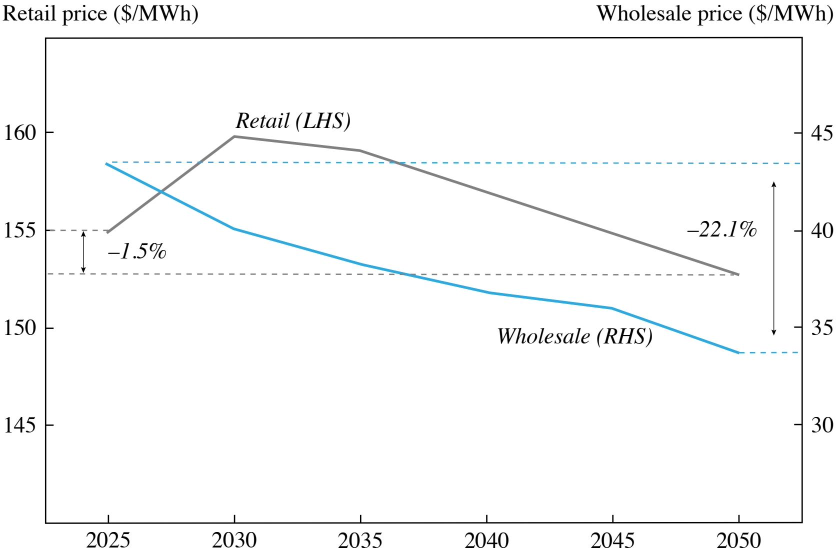
While much of this comment focuses on the electricity price results, I also discuss the authors' findings on the economic gains in the United States from lower electricity prices. Conditional on the decline in electricity prices that the authors forecast, I argue that their macroeconomic effects are *underestimated*. In particular, their first-order approach does not capture potential relocation of industrial and manufacturing activity within the United States and from around the world to locations with a low wholesale cost of electricity.

WHOLESALE ELECTRICITY PRICES

Energy systems modeling. The finding of 20–80 percent declines in wholesale electricity costs generally contrasts with findings in the engineering and energy systems modeling, which attempt to project the evolution of the US electricity markets or the US energy system more broadly in light of cost declines for solar, wind, and batteries. Energy systems models are partial equilibrium or industry equilibrium models that typically have detailed spatial representations of electricity production and demand, transmission constraints, and current and projected technology costs that dictate the evolution of the generation mix. These models have proven influential in the analysis of energy, environmental, and climate policy (for example, see Bistline, Mehrotra, and Wolfram 2023 for an analysis of the energy market impacts of the Inflation Reduction Act).

As figure 1 shows, this literature does find substantial declines in wholesale electricity prices, but at the lower end of what Arkolakis and Walsh project and at a later date. Drawing from business-as-usual projections in Bistline and others (2023) and for the models that project electricity prices, these models see a 15 percent decline in wholesale prices by 2040 and a

Figure 1. Change in Wholesale and Residential Electricity Prices Across Eleven Energy Systems Models



Source: Author's analysis of business-as-usual projections in Bistline and others (2023).

22 percent decline in 2050.[1] Prices fall from approximately $43 to $37 per megawatt-hour (MWh) by 2050; these price declines are sizable on average but small relative to the volatility of wholesale electricity prices. In sharp contrast, the authors project a nationwide average 37 percent decline in wholesale electricity costs by 2040 driven by sharp drop in the price of firmed solar. Differences in solar potential account for their range of 20–80 percent price declines across locations in the United States.

In contrast to wholesale electricity prices, residential electricity prices show more muted changes in energy system modeling. The average across the eleven models studied by Bistline and others (2023) sees a 1.5 percent decline in residential electricity prices by 2050. In the near term, residential electricity prices are expected to rise due to increased expenditures for transmission and distribution that represent an important component of residential prices.

1. These models sometimes generate larger declines in electricity prices, but only by considering the impact of additional policies that are not considered in the paper, such as a carbon tax or net zero by 2050 commitment.

Table 1. Capital Cost and Levelized Cost of Electricity (LCOE) for Various Generating Technologies

	Capital cost					
	$/kW			Change from 2023 (percent)		
	2023	2040	2050	2040	2050	
Natural gas	1,522	1,309	1,206	−14	−21	
Solar PV	1,611	825	683	−49	−58	
Solar PV + 4-hour battery	2,590	1,400	1,154	−46	−55	
	LCOE					
	$/MWh			Change from 2023 (percent)		Capacity factor
	2023	2040	2050	2040	2050	
Natural gas	44	41	40	−6	−10	0.66
Solar PV	43	23	20	−47	−55	0.33
Solar PV + 4-hour battery	93	55	47	−41	−49	0.33/0.16

Source: Capital costs are taken from the moderate scenario in NREL's 2023 ATB data and levelized cost is computed using the NREL ATB's fixed cost, variable cost, and heat rate assumptions. Fuel cost and other parameters are available in the online data appendix. Capacity factors as specified in last column. "PV" for "photovoltaic."

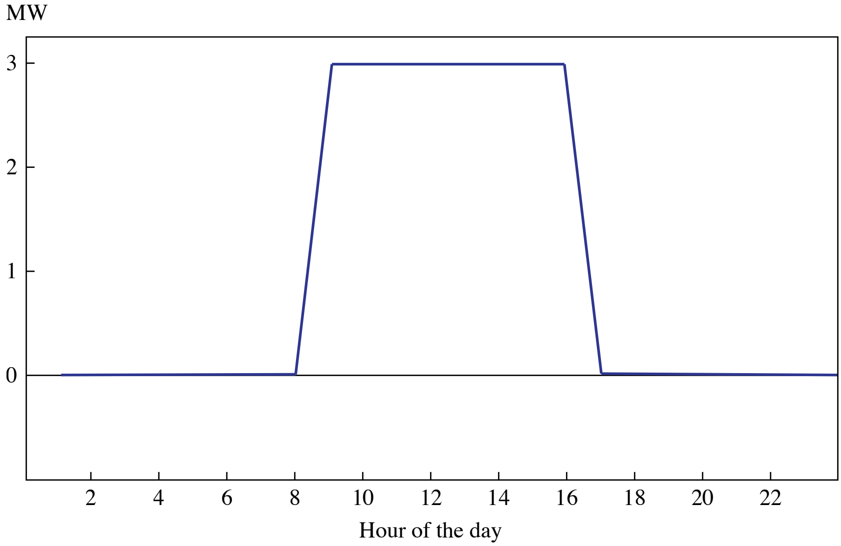
So what accounts for the difference between the authors' projection and the findings from energy systems models? One possibility is that the authors may have more optimistic assumptions about the price declines for solar and batteries relative to energy systems models, as future technology costs are an important input for these models. The top panel of table 1 shows forecasts for the capital costs per kilowatt (kW) of capacity for three types of generation technology: natural gas, solar, and solar with four-hour battery storage. These forecasts are from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) for 2023 and typically form the basis for technology projections in energy systems models.[2]

The NREL ATB sees large declines in the capital cost for solar and batteries through 2040 and 2050. The capital cost for utility-scale solar is expected to fall 49 percent by 2040 and nearly 60 percent by 2050.[3] Solar

2. The ATB provides a forecast updated annually for capital costs to 2050 based on recent trends in capital costs for current (i.e., solar and wind) and prospective generation technologies (i.e., enhanced geothermal or natural gas with carbon capture). The 2023 ATB data can be found at https://atb.nrel.gov/electricity/2023/data.

3. Table 1 shows capital costs under ATB's moderate technological progress scenario.

Figure 2. Twenty-Four-Hour Electricity Demand Profile (Demand During the Day)



Source: Author's calculations and illustration.

paired with batteries is also expected to see sharp price declines of a similar magnitude. By contrast, price declines are more muted for natural gas, falling about 20 percent by 2050. These price declines are comparable to those projected by the authors. As reported in figure 2 in the paper, solar plus batteries is expected to fall 73 percent by 2040; these declines are larger than shown in the ATB data. But price declines by 2050 are commensurate. Therefore, the main difference in capital cost assumptions between the authors and ATB seems to be that the former assume a somewhat faster decline but of similar magnitude.[4]

System versus levelized cost of electricity. If differences in technology cost do not account for differences in electricity prices, what does? Arkolakis and Walsh's measure of electricity costs is analogous to the levelized cost of electricity (LCOE). Levelized cost is a measure of the break-even price of electricity for a given generation technology—the average price of electricity net of fuel and other fixed and variable costs that covers

4. See figure 5 in the paper for a comparison of the authors' capital cost declines relative to energy systems models.

the initial capital cost. The derivation for the levelized cost of a generation technology i is given below:

$$P_i^k = \sum_{t=1}^{T} \frac{P_i^e \theta_i - \phi_i - F_i \theta_i}{\left(1+r\right)^t}$$

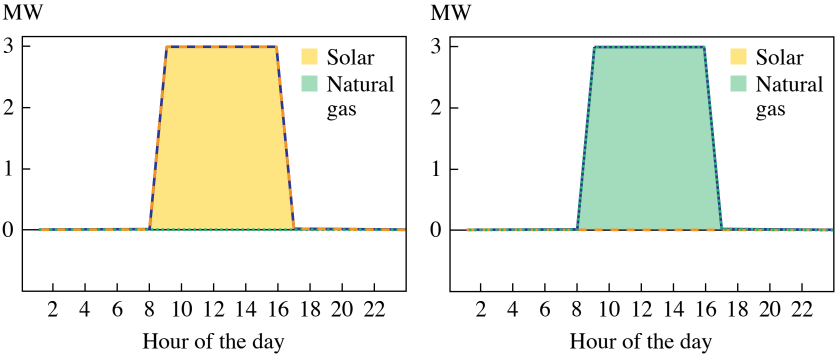
$$\Rightarrow P_i^e = F_i + \theta_i^{-1}\left(\phi_i + P_i^k C\left(r\right)\right),$$

where P_i^e is the LCOE for technology i (in \$/MWh), P_i^k is the cost of capital (in \$/kW), F_i is a variable cost including fuel cost (in \$/MWh), r is the cost of capital, T is the economic lifetime of the capital, and ϕ_i is a fixed cost (in \$/kW). $C(r)$ is the inverse of the annuity value for \$1 received for T years and reflects the yearly charge to recover the initial capital expenditure. The capacity factor θ_i, expressed in MWh/kW, is a key variable influencing the LCOE. It represents the fraction of time in a year that generation capital is producing a full capacity. For fossil fuel technologies, a generator can choose how intensively to operate subject to required downtime. For solar and wind, the capacity factor is dictated by conditions as these power generation sources are intermittent. All else equal, a higher capacity factor lowers the levelized cost.

The lower panel of table 1 shows the LCOE for natural gas, solar, and solar backed with batteries, using data from the NREL ATB. The sharp decline in capital costs largely passes through to the LCOE for solar and solar firmed with batteries. Both technologies see a roughly 50 percent decline in levelized cost by 2050, again comparable to the levels found by the authors. This is not surprising given the expression for LCOE. Since renewables have zero variable costs, a given percentage decline in capital costs has an equivalent effect on levelized cost. The authors' derivation of electricity costs differs in some minor ways from levelized cost but maintains the same idea of proportional declines in capital cost, implying proportional declines in wholesale electricity prices.

However, while LCOE may be useful as a marginal concept, it has drawbacks as a system concept. The price of electricity must be sufficient to ensure that electric power generation is sufficient to meet demand at all times, and the price required to accomplish this may be quite different from the breakeven price for a single type of generation. A series of simple examples can help illustrate the divergence between the system cost of electricity and the levelized cost. The system cost of electricity is defined as the price of electricity P_e that satisfies the following condition:

Figure 3. Twenty-Four-Hour Electricity Demand and Supply Profiles (Demand During the Day Supplied by Natural Gas or Solar Only)



	System cost of electricity ($/MWh)			Capacity factor
	2023	2040	2050	
Natural gas only	65	60	57	0.33
Solar only	43	23	20	0.33

Source: Author’s calculations and illustration.

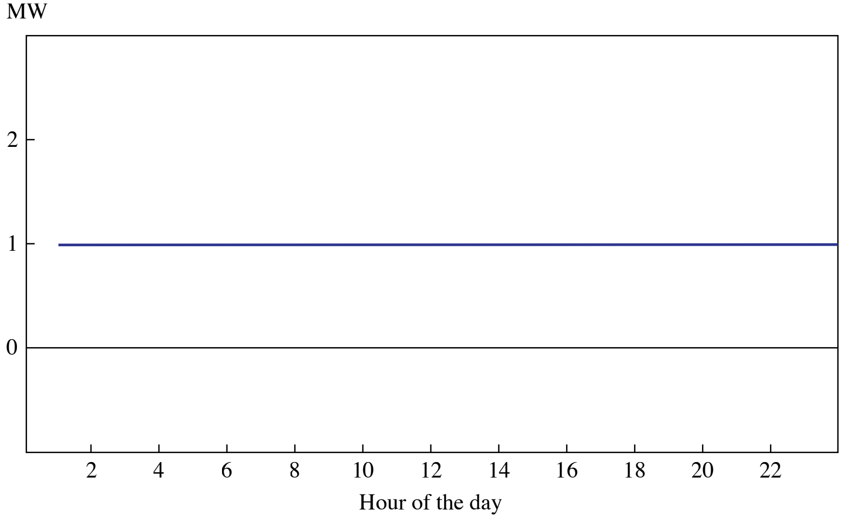
$$\sum_i P_i^k K_i = \sum_i \sum_{t=1}^{T} \frac{\left(P_e \widetilde{\theta}_i - \phi_i - F_i \widetilde{\theta}_i\right) K_i}{\left(1+r\right)^t},$$

where $\widetilde{\theta}_i$ are the endogenous capacity shares of each generation technology needed to satisfy the shape of overall demand. LCOE differs from technology to technology, while the system cost depends on the exact mix of generation technologies that are utilized to meet overall demand.

Consider the simple demand shape shown in figure 2, where electricity demand is only present during the day and falls to zero at night. The x-axis has hours of the day and the y-axis shows demand in megawatts at each hour of the day. Either solar or natural gas could be used to provide enough generation to meet demand during the day; batteries in this case would be superfluous. Using the same capital cost numbers in table 1, the breakeven electricity cost is calculated relying only on solar or only on natural gas.

As figure 3 shows, relying only on solar is the cheapest option under this stylized demand schedule. Moreover, the system cost equals the LCOE for solar because the capacity factor for solar needed to match overall demand

Figure 4. Twenty-Four-Hour Electricity Demand Profile (Demand of 1 MW at All Hours)



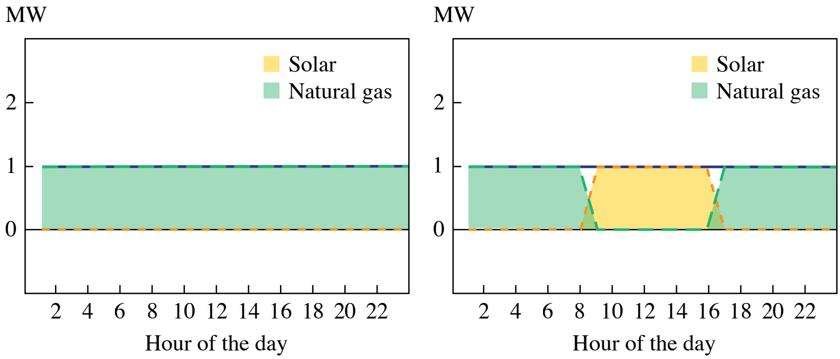
Source: Author's calculations and illustration.

is the same as the assumed capacity factor for a single solar generator. The overall cost of electricity using just natural gas is *higher* than its LCOE because the capacity factor is lower. Essentially, the 3 MW of gas generation are left idle for two-thirds of each day. While the same is true for solar, the absence of any fuel cost makes it the cheaper option, and declining capital costs raise its price advantage in the future.

However, when we consider another more realistic demand schedule, the advantages of solar relative to natural gas generation are greatly reduced. Figure 4 shows a demand schedule with a constant 1 MW of electricity demand at all hours. Total demand each day—24 MWh—is the same as in the first example. One way to meet demand would be to use only natural gas, installing 1 MW of gas capacity. Another option would be to combine 1 MW of natural gas with 1 MW of solar that meets demand during the day. A third option would be to rely only on solar and batteries, installing 3 MW of solar and two 1 MW/8 MWh utility-scale batteries.[5] Figure 5 shows the

5. The precise combination of batteries required depends on their instantaneous capacity to charge or discharge and their capacity (i.e., how many megawatt-hours they can store). In this case, the batteries must be able to charge and discharge at 1 MW to fully charge during the day and to meet demand at night.

Figure 5. Twenty-Four-Hour Electricity Demand and Supply Profiles (Demand of 1 MW at All Hours Supplied by Natural Gas Only versus by Solar and Natural Gas)



Source: Author's calculations and illustration.

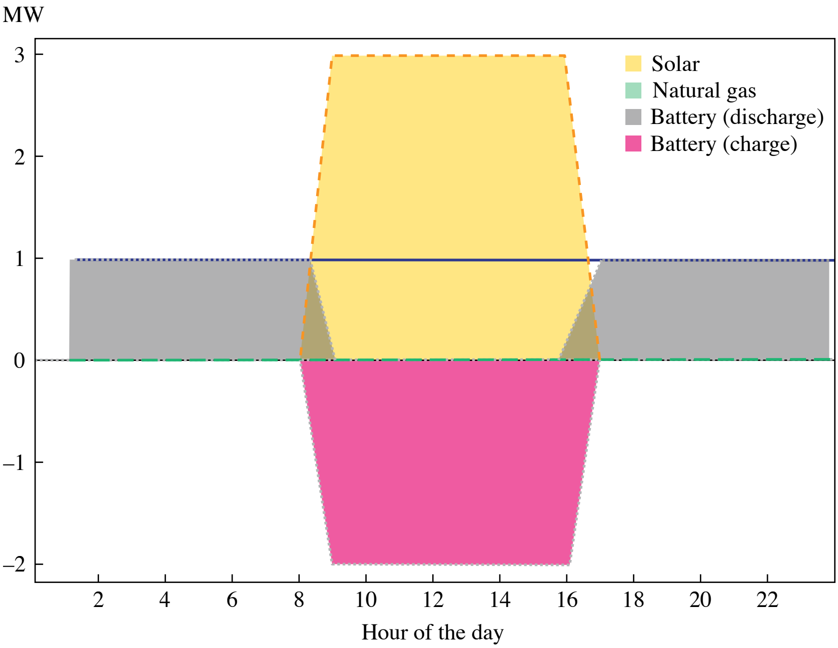
first two options while figure 6 shows the solar and battery option. The table below figure 6 shows the system cost of electricity for each option.

As the table under figure 6 shows, the cheapest option at today's prices would be to use only natural gas, despite the fact that solar has a lower LCOE than gas. Projected declines in solar costs make a combination of natural gas and solar the cheapest option in 2040 and 2050. By contrast, relying just on batteries and solar is the most costly option in all years, though the premium relative to the other options comes down as solar and battery costs fall. From the perspective of an energy systems modeler, the decline in wholesale prices is less than 10 percent despite nearly 50 percent declines in the cost of technology (including sizable declines in capital cost of natural gas).

The reason for the limited gains from lower technology costs is that solar and batteries often need to be paired with other generation. As those technologies provide a larger share of total generation, the capacity factors fall for the dispatchable generator, raising system costs. Essentially, costly generation capital is kept on standby for long periods. Again, LCOE and system cost are not the same, and conclusions drawn from extrapolating from changes in LCOE would be misleading.

The relationship between LCOE and system cost is more straightforward in the case where natural gas is paired with solar. Note that, in this case, the capacity factors for both natural gas and solar are equal to the assumed capacity factors in the LCOE calculation. Given this, the system cost is the weighted average of levelized cost for each technology where

Figure 6. Twenty-Four-Hour Electricity Demand and Supply Profiles (Demand of 1 MW at All Hours Supplied by Solar and Battery)



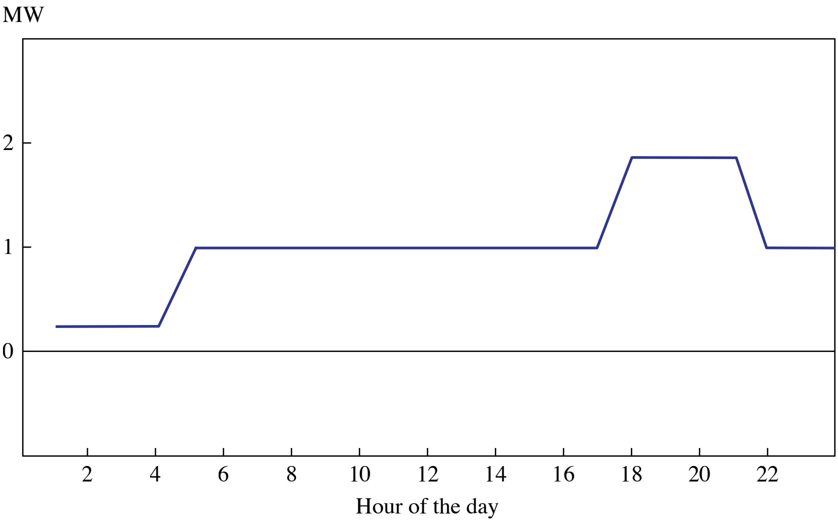
	System cost of electricity ($/MWh)			Capacity factor
	2023	2040	2050	
Natural gas only	37	35	34	1.00
Solar + natural gas	44	35	33	0.33/0.66
Solar + storage	96	52	43	0.33/0.33

Source: Author's calculations and illustration.

the weight is each technology's generation share. Falling solar prices lower the system cost but at a weight equal to their generation share, which is only one-third.

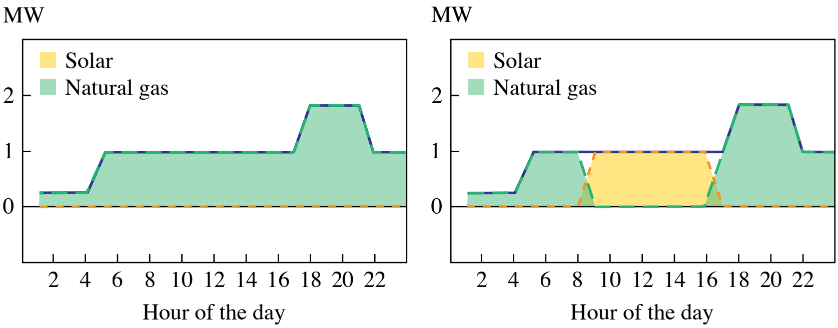
Last, it is worth considering the generation mix in a more realistic scenario where demand rises in the evening and falls in the middle of the night. Figure 7 shows such a scenario, with 75 percent higher demand for four hours in the evening and 75 percent lower demand overnight. Total demand remains the same as the two earlier scenarios at 24 MWh per day. Figures 8 and 9 together show four scenarios: 1) a natural gas only option;

Figure 7. Twenty-Four-Hour Electricity Demand Profile (Demand Rises in the Evening and Falls in the Middle of the Night)



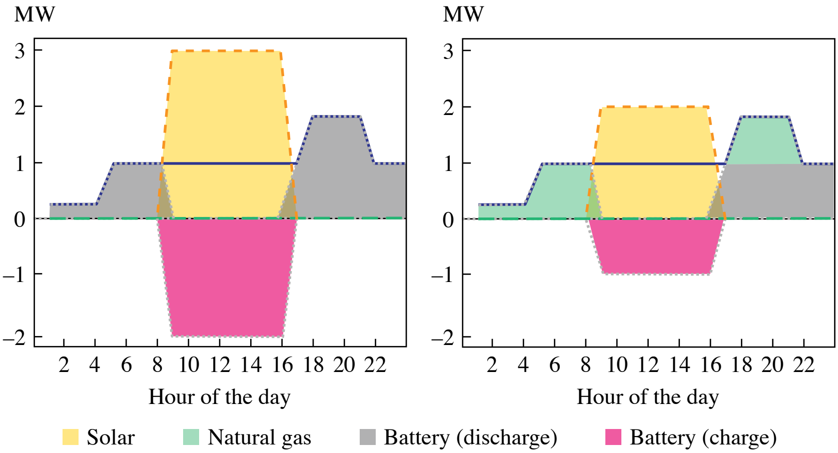
Source: Author's calculations and illustration.

Figure 8. Twenty-Four-Hour Electricity Demand and Supply Profiles (Realistic Scenarios: Solar Only versus Solar and Natural Gas)



Source: Author's calculations and illustration.

Figure 9. Twenty-Four-Hour Electricity Demand and Supply Profiles (Realistic Scenarios: Solar and Battery versus Solar, Battery, and Natural Gas)



	System cost of electricity ($/MWh)			Capacity factor
	2023	2040	2050	
Natural gas only	47	44	42	1.00
Solar + natural gas	54	44	42	0.33/0.66
Solar + storage only	96	52	43	0.33/0.33
Solar + storage + natural gas	73	47	41	0.33/0.33/0.33

Source: Author's calculations and illustration.

2) natural gas and solar with no batteries; 3) a zero emissions scenario with only solar and batteries; and 4) a combination of gas, solar, and batteries. The system cost of electricity across each scenario is shown in the table below figure 9.

This scenario shows again that levelized cost and system cost are not strongly linked. Across the lowest cost options, electricity prices fall 14 percent from 2023 to 2050 despite 50–60 percent declines in capital costs. Importantly, across the three scenarios, the lowest cost option in a given year is *rising* despite total demand remaining constant. As the scenarios get more realistic, the capacity needed to meet demand rises and utilization rates fall; the last pieces of the puzzle to match demand come at a high cost. Thus, these components of supply have an outsized role in determining breakeven prices.

As shown in the table under figure 9, natural gas only is the cheapest option using current prices, but note that its capacity factor is no longer 100 percent; a total of 1.75 MW of natural gas must be installed to meet peak demand. In the previous scenario of constant 1 MW of demand, only 1 MW of generation was needed. The extra 0.75 MW of capacity is only used at the evening peak and is unused for the remaining twenty hours in the day. Solar paired with natural gas becomes cost competitive in 2040, as solar has a relatively high utilization rate. However, the presence of solar does not lower the capital needs from natural gas; it is still the case that 1.75 MW of natural gas generation capacity must be present to meet the evening peak.

The scenarios relying on batteries only become cost competitive in 2050, though the zero emissions scenario that eliminates natural gas still remains marginally more expensive. The zero emissions option is expensive because of the large amount of solar and batteries that are needed and their relatively low capacity factors. In the zero emissions scenario, 3 MW of solar are paired with 2 MW/16 MWh of battery storage. Importantly, batteries must have 2 MW of instantaneous charging capacity to fully charge in the eight hours that solar is producing.

Pairing 2 MW of solar with 1 MW/8 MWh of batteries and 0.75 MW of natural gas offers the lowest cost option for generation in 2050. This combination maintains the highest capacity factors primarily by allowing the dispatchable generation asset—natural gas—to ramp up to meet the demand peak in the evening and kick in when batteries are no longer producing. This scenario lowers the amount of solar and batteries installed in exchange for natural gas. Importantly, in the least costly option, one-third of total power generation still comes from natural gas. Incidentally, the generation mix in this last scenario appears to best mimic the generation mix shown in energy systems models for the 2050 generation mix absent a zero emissions target (see Mehrotra 2024).

As these scenarios illustrate, levelized cost and the system cost of electricity are differing concepts, and the portion of the cost of electricity needed to cover the "last mile" of generation assets is often of first-order importance. An analytic expression can be derived, showing how differing levels of capacity utilization can drive the system cost of electricity beyond the levelized cost:

$$P^e = \sum_i \omega_i \left(P_i^e + \left(\widetilde{\theta}_i^{-1} - \theta_i^{-1} \right) \left(\phi_i + C(r) P_i^k \right) \right),$$

where i indexes a particular generation technology, $\omega_i = \widetilde{\theta}_i K_i / \sum_i \widetilde{\theta}_i K_i$, the generation weighted share of electricity production, P_i^e is the levelized cost of electricity, θ_i is the assumed capacity factor in levelized cost, and $\widetilde{\theta}_i$ is the actual capacity factor for technology i. The terms P_i^k, ϕ_i, and $C(r)$ are the per watt capital cost, fixed cost, and inverse annuity factor, respectively.

This expression shows that the system cost of electricity is the generation weighted sum of the levelized cost plus a second term that represents the carrying cost of underutilized assets: the gap between the actual capacity factor for technology i and its assumed capacity factor in the levelized cost calculation. To the extent that the generation asset is underutilized, the extra fixed and capital costs are incurred, which must be covered by the overall electricity cost.

It should be emphasized that the examples presented here understate the challenge of relying primarily on solar, wind, and batteries for most or all of electric power generation. The examples constructed here were still favorable for solar and batteries. For solar, the examples considered had no seasonal variation or no possibility of variable solar output from weather. For batteries, the predictability of solar ensured predictable charging and discharging patterns, so that batteries could have a high utilization rate. Demand was also not subject to any daily or seasonal variations.

The challenge of relying on intermittent renewables is likely to be further complicated in zero emissions scenarios when dispatchable sources of generation are needed to deal with supply and demand variability. Currently, natural gas is the most economical dispatchable resource. Using carbon capture, green hydrogen, or geothermal to play the role of a dispatchable resource is likely to be costly, particularly if utilization rates are low. Furthermore, in an energy transition, electricity demand is likely to rise, particularly in times when solar energy is not being generated in the winter and at night.[6]

Evidence from recent history. Recent trends in US electricity prices also raise questions about whether future declines in generation costs will drive declines in end-use electricity prices. The top four rows of table 2 show US electricity prices in constant dollars over the most recent five-year period (2019–2023) and comparable periods from twenty and fifteen years ago (i.e., 1999–2003 and 2004–2008).[7] Real electricity prices have

6. Electric vehicles are less efficient in winter and are typically charged at night, particularly for commercial transportation. Electric heating demand will also be higher in winter.

7. All prices are converted to 2023 dollars using the price index for GDP.

Table 2. Electricity Prices and Input Costs for Electric Power Generation

	Level			*Change (percent)*	
	1999–2003	*2004–2008*	*2019–2023*	*Twenty-year*	*Fifteen-year*
Electricity cost					
Residential cost (2023 ¢/kWh)	13.9	14.8	15.5	12	5
Industry cost (2023 ¢/kWh)	7.9	8.9	8.1	3	–9
PPI: electricity to industry (2023 = 100)	89	92	95	7	3
PPI: electricity to commerce (2023 = 100)	75	82	95	27	16
Fuel cost					
Coal (2023 $/MMBtu)	2.04	2.45	2.35	15	–4
Natural gas (2023 $/MMBtu)	6.37	10.87	3.78	–41	–65
Capital cost					
Ten-year Treasury rate	5.1	4.3	2.3	–55	–47
Price index for turbines (2017 = 100)	112	105	98	–12	–7
Price index for electric power structures (2017 = 100)	89	101	94	6	–6
Wages					
Electric power generation (relative to nonfarm private)	1.73	1.75	1.70	–2	–3

Source: Electricity prices are from EIA's *Electric Power Annual 2023*. PPI and wages are from the Bureau of Labor Statistics. Price indexes for equipment and structures are from the Bureau of Economic Analysis.

Note: Prices and fuel costs are expressed in real 2023 dollars or index values. Wages are relative to nonfarm wages for nonsupervisory and production workers.

risen 12 and 5 percent, respectively, for residential consumers as reported by the Energy Information Administration (EIA). However, the increase for residential consumers could be driven by increasing costs for transmission and distribution.

A better indicator for trends in wholesale prices would be the price charged to industrial and commercial users. Real prices for industrial users as reported by the EIA have remained roughly flat, rising 3 percent over a twenty-year period but falling 9 percent over a fifteen-year period.[8] However, producer price index (PPI) shows more definitive increases in prices charged to industrial and commercial users. The PPI for electricity prices to commercial users is up 27 percent over twenty years and 16 percent over fifteen years.[9] Broadly, both the EIA and PPI data suggest an increase in wholesale real electricity prices over the last fifteen or twenty years.

Over this same period, generator costs appear to have fallen sharply. Fuel cost—representing about one-third of LCOE based on my calculations—has fallen sharply for natural gas. With the shale revolution, the real cost of natural gas has fallen 40–60 percent over the past fifteen to twenty years. The real cost of coal has also fallen 4 percent over the past fifteen years. Major capital costs also appear to have fallen over this period. The price index for turbines and for electric power structures as reported in Bureau of Economic Analysis investment price indexes has fallen 7 and 6 percent, respectively, over the last fifteen years.[10] This is consistent with the general decline in the relative price of capital goods in recent decades. The real interest rate has also fallen sharply over the past two decades, with the ten-year Treasury rate at roughly half of its 2000 level.

Likewise, the cost of labor for operating utilities does not appear to have meaningfully changed relative to wages in the rest of the economy. As the last row of table 2 shows, the wage premium for workers in the electric power utilities has remained stable relative to broader wage measures. In any case, labor costs are a relatively small component of the cost of producing electricity. Overall, available evidence on labor, capital, and fuel

8. EIA, "Table 2.4. Average Price of Electricity to Ultimate Customers by End-Use Sector," in *Electric Power Annual 2023,* https://www.eia.gov/electricity/annual/table.php?t=epa_02_04.html.

9. Bureau of Labor Statistics, PPI Databases," https://www.bls.gov/ppi/databases/.

10. Bureau of Economic Analysis, "National Data National Income and Product Accounts," under "NIPA Tables": "Table 5.4.4. Price Indexes for Private Fixed Investment in Structures by Type" and "Table 5.5.4. Price Indexes for Private Fixed Investment in Equipment by Type," https://apps.bea.gov/iTable/?reqid=19&step=2&isuri=1&categories=survey.

costs suggests that the cost of producing electricity has fallen meaningfully over the last fifteen or twenty years. But that decline in generator costs has not been passed on to consumers.

The divergence between the cost of generation for utilities and electricity prices despite the sharp decline in capital and fuel costs merits further study. This lack of pass-through may reflect issues of market structure or the regulation of utilities. Werner and Jarvis (2024) document that the rate of return for regulated utilities has stayed largely unchanged over recent decades despite the sharp drop in interest rates, perhaps reflecting inattention from regulators. Environmental or other regulatory compliance costs may also account for the gap between electricity prices and input costs.[11]

NATIONAL AND LOCAL ECONOMIC EFFECTS While much of my discussion has focused on the authors' conclusions about electricity prices, a significant portion of their work is devoted to understanding the national and local implications of a substantial fall in electricity prices driven by solar and battery advances. My overall conclusion here is that, if anything, their conclusions about macroeconomic effects are likely understated. While their local and national wage gains appear sensible, their analysis does not include additional channels through which lower electricity prices provide benefits. And if price drops in solar and batteries trigger a persistent rise in total factor productivity (TFP) growth that reverses the 1970s slowdown in TFP growth (as they speculate), those gains would completely dominate any other channel.

Arkolakis and Walsh assess regional wage impacts by deriving a condition relating changes in local wages to changes in local electricity prices. Consider any regional production function that is Cobb-Douglas in its factors of production, including electricity E:

$$Y = F\left(E, N\right) = E^{\eta} N^{1-\eta}.$$

For a representative firm hiring factors in a competitive market, labor demand and electricity demand are given by standard first-order conditions:

$$w = \left(1 - \eta\right) E^{\eta} N^{-\eta}$$

$$p_e = \eta E^{\eta - 1} N^{1-\eta}.$$

11. In California, the high cost of electricity is, in part, due to utility costs passed on to consumers for reducing wildfire risks and ensuring resilience to extreme weather.

Solving for E in the second equation and substituting into the first equation, employment drops out and wages are only a function of the price of electricity. In logs, the following equation obtains:

$$\ln(w) = c - \frac{\eta}{1-\eta}\ln(p_e),$$

where c is a constant and η is electricity's cost share in the production function. A similar equation holds with other inputs in the production function such as capital and intermediates, so long as the real price of those inputs is invariant to the decline in the real electricity price.

The authors emphasize that their wage expressions reflect a firm free entry condition; a decline in the price of electricity causes firms to make profits, which incentivizes entry and bids up wages. The emphasis on the extensive margin of free entry is not clear. In the expression derived here, expansion comes from the intensive margin; the representative firm optimally becomes larger and produces more in response to the drop in an input cost. The qualitative and quantitative implications seem similar, so it is not clear whether the distinction is important.

Electricity's share of US GDP is 1.1 percent, meaning a 20–80 percent decline in electricity prices raises wages by 0.4 to 1.5 percent.[12] This is of similar magnitude to the 2–3 percent increases in nationwide GDP. The slightly larger increase found in the paper may reflect factor reallocation gains across industries in regions with large electricity price declines or the fact that regional price declines are concentrated in places that are relatively intensive in their electricity use. This seems plausible given their list of the places that experience the largest wage increases (see table 2 in the paper's online appendix).

The authors' methodology to calculate economic impacts may miss other important channels through which lower electricity prices boost welfare. For instance, a substantial share of electricity is consumed directly by households (more than one-third of electricity consumption).[13] A lower price would boost residential usage and household welfare, but it is unclear why the authors' wage-based methodology would capture this channel. Any wage increase for higher household electricity consumption would likely come indirectly via wealth effects on labor supply.

12. Bureau of Economic Analysis, "Interactive Access to Industry Economic Accounts Data," under "Value Added by Industry," https://apps.bea.gov/iTable/?reqid=150&step=2&isuri=1&categories=gdpxind.

13. EIA, "U.S. Energy Facts Explained," see chart "U.S. Energy Consumption by Source and Sector, 2023," https://www.eia.gov/energyexplained/us-energy-facts/.

The authors' methodology also does not consider reallocation of production across regions or countries. This reallocation of industrial activity is likely to be significant given the electricity price declines the authors project. Certain activities are heavy users of electricity (e.g., aluminum production, data centers, or bitcoin mining), and the locations of such activities are likely to display a fairly high elasticity to the long-run electricity price. While most residential and commercial activities are unlikely to shift location solely due to electricity prices, the same should not hold for industrial activities. Already, the steep rise in European energy prices due to the Russian invasion of Ukraine has resulted in reductions in energy-sensitive manufacturing and a shift in production to locations with cheaper energy. The US Inflation Reduction Act may also be luring more electricity intensive activity to the United States, in part due to expectations of lower electricity prices.

The transition to net zero emissions is likely to further reallocate industrial activity to locations with cheap electricity. Decarbonization of industrial emissions requires shifting from use of coal and natural gas for industrial heating to heat pumps, green hydrogen, and thermal batteries. Those technologies require plentiful electricity to generate heat instead of burning fossil fuels. Direct emissions from the production of steel and cement can also be decarbonized by relying on electric arc furnaces, electrolysis, or carbon capture technologies that will require plentiful electricity. The long-term shift of industrial activity to places with abundant clean electricity seems likely to play out in the coming decades, benefiting locations with high renewable energy potential.

Finally, the wage gains and other welfare gains outlined here likely pale in comparison to the (admittedly speculative) effects on TFP growth. An extensive body of literature has theorized that the slowdown in US TFP growth was caused by oil price shocks of the 1970s and structurally higher energy prices. Arkolakis and Walsh noted that cheap renewable power may represent the opposite shift, putting US TFP growth back at postwar levels. If such an outcome is realized, the gains dwarf the wage gains considered here. This line of inquiry—the link between energy prices and TFP growth—seems to be of first-order importance in further work.

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Mehrotra, Neil R. 2024. "The Macroeconomics of Net Zero." Working Paper. Minneapolis, Minn.: Federal Reserve Bank of Minneapolis.

Werner, Karl Dunkle, and Stephen Jarvis. 2024. "Rate of Return Regulation Revisited." Working Paper 329. Berkeley, Calif.: Energy Institute at Haas, University of California, Berkeley.

GENERAL DISCUSSION Steven Davis cautioned that politicized and inefficient retail pricing of electricity could reduce cost savings from clean energy. He remarked that in California, at least in his residential neighborhood, electricity prices are lowest after midnight—a time when solar power isn't generated—despite California's push to promote solar power.

Conor Walsh observed that energy system models often miss an equilibrium condition: The US generation markets are now largely decentralized in both location and distribution. He described the scenario in which, with dispatchable solar backed by storage, a merchant plant can decide when to supply its solar energy. If market prices are higher than the plant's levelized cost of energy, market entry is induced.

Caroline Hoxby inquired about the divergence between wholesale energy prices and recent retail price increases, specifying that consumers respond to retail prices. In response, Walsh stated that this divergence has partly been driven by unexpectedly flat demand growth over the past twenty years. Utility companies were expecting higher demand growth, so they overinvested in distribution infrastructure and passed some of the costs on to consumers, he explained.

On the topic of high retail prices, Neil Mehrotra provided two further explanations. First, spending on infrastructure related to climate change has been captured in retail prices. For example, wildfire mitigation is expensive and has been incorporated into California's prices. He pointed out that commercial and industrial energy prices have also drifted up, despite falling natural gas prices and lower capital costs. Postulating another reason for higher energy prices, he mentioned a paper demonstrating that utility commissions have not updated the regulated rate of return, the interest rate that they use, to reflect lower current market interest rates.[1]

1. Karl Dunkle Werner and Stephen Jarvis, "Rate of Return Regulation Revisited," working paper 329R (Berkeley, Calif.: Energy Institute at Haas, 2024).

Underscoring the importance of considering retail prices, Koichiro Ito commented that the divergence between wholesale and retail prices depends on the specific prices one is comparing and state-level regulations. Jón Steinsson added that large industrial users pay wholesale prices, not retail prices, so people shouldn't be thinking about the whole market as paying retail.

Abigail Wozniak encouraged those working on topics related to clean energy to think further about welfare impacts at the community level. While lower prices and overall gains sound positive, she warned that economists have historically lost credibility for failing to recognize how use of technology and certain policies would be received by individual communities. Wozniak suggested using public data from community hearings and utility commissions to understand community impacts more quickly and accurately. She concluded with the concern that rapid change generally isn't welfare-enhancing for everyone.

On the other hand, Steinsson proposed that the authors might be underestimating benefits from the clean energy transition by not accounting for electrification. The authors' estimates of a 2–3 percent wage increase are based on the current cost share of electricity. However, if sectors like home heating and transportation become electrified, the cost share of electricity will increase significantly, potentially multiplying the benefits by a factor of two or three. He also acknowledged challenges limiting rapid growth, such as the interconnection queue and finite land.

Mehrotra observed that electrification also poses obstacles for renewables because currently peak electricity demand occurs in the summer, but with increased use of heat pumps and electric cars, peak demand would shift to winter, when solar energy production is at its lowest. This shift could lead to expensive reliance on natural gas power plants to meet winter demand. In response, Walsh mentioned that wind power tends to produce more in winter, which could help offset this issue.

Adele Morris emphasized the role of policies such as subsidies for electrification, state-level initiatives such as the Regional Greenhouse Gas Initiative (RGGI), California's Assembly Bill 32, and renewable energy mandates. She also contended that utilizing land for solar deployment will come at a cost and may impact land markets, arguing that a comprehensive welfare analysis should consider changes in land prices. Last, she brought up the air quality improvements and resulting societal benefits that would stem from increased renewable energy use.

Susan Athey discussed the importance of incorporating demand and time of day variations into projections. She advocated for analyzing both the supply and demand curves separately, as both have unique determinants and implications. She also suggested that improving transmission infrastructure could boost the GDP, pointing out that the people who make decisions about transmission often benefit from high transmission prices and therefore favor high prices over consumer interests and economic growth.

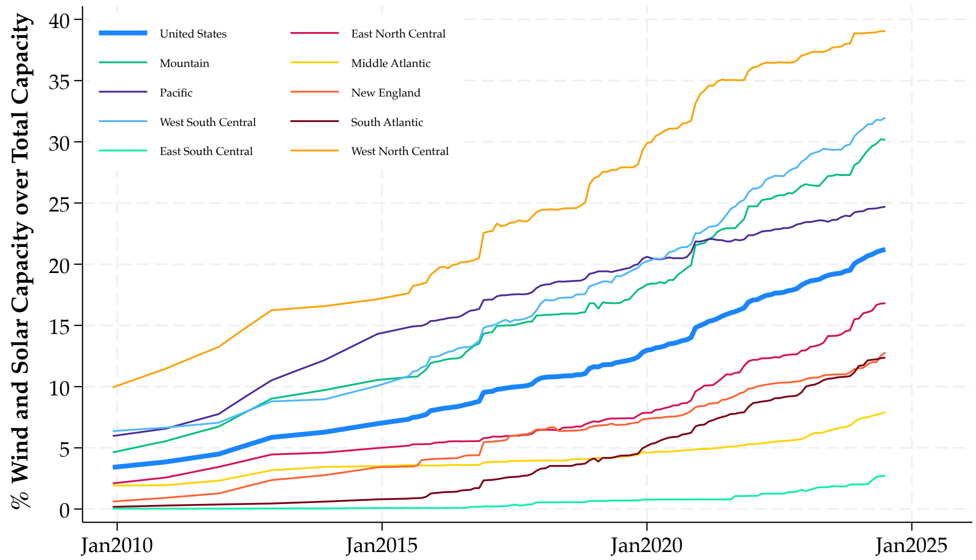
Wendy Edelberg reflected that even two years ago experts in economics and climate science were concerned that slow demand growth would hinder the transition to renewable energy and make it difficult to justify investments in necessary infrastructure. However, this concern has now been overturned by faster-than-expected demand growth. Edelberg pondered how this rapid demand increase will affect future projections.

Christina Romer raised concerns about the long-term outlook on solar prices, highlighting that much of the price reduction comes from technological innovation in China. She questioned how trade policy, such as the US government's push to block Chinese solar panels over accusations of predatory pricing, might affect the market. Walsh agreed that there is evidence of predatory pricing, noting that Chinese solar manufacturers have been producing below cost since the Obama administration, with the situation worsening over time due to lower costs and increased capacity in China. Ito added that this issue is even more critical for energy storage, as the government is considering different policies for Chinese versus US batteries, which could influence future battery costs.

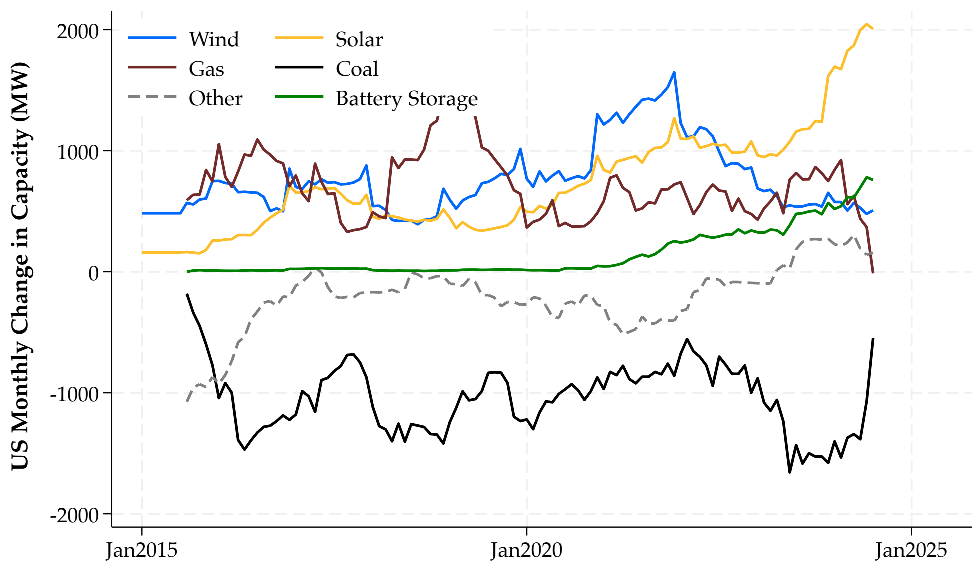
Shifting the discussion to the interconnection queue, Henry Aaron asked about the reasons behind the delay, how much it would cost to reduce the delay, and how investments to address the queue could be dynamically scored. Walsh acknowledged that the queue is a significant problem—delaying projects shifts revenues forward in steady-state analyses. He also noted that the delay increases the risk that projects may never exit the queue, leading some companies to leave it altogether. Ito explained that the interconnection system was created decades ago, when only a few coal or gas projects entered the market at a time. Now, with hundreds of renewable projects, there's a capacity issue in assessing them, compounded by speculative entries where companies submit multiple proposals, hoping one succeeds.

A Figures and Tables

Figure 17: Renewable Investment Detail



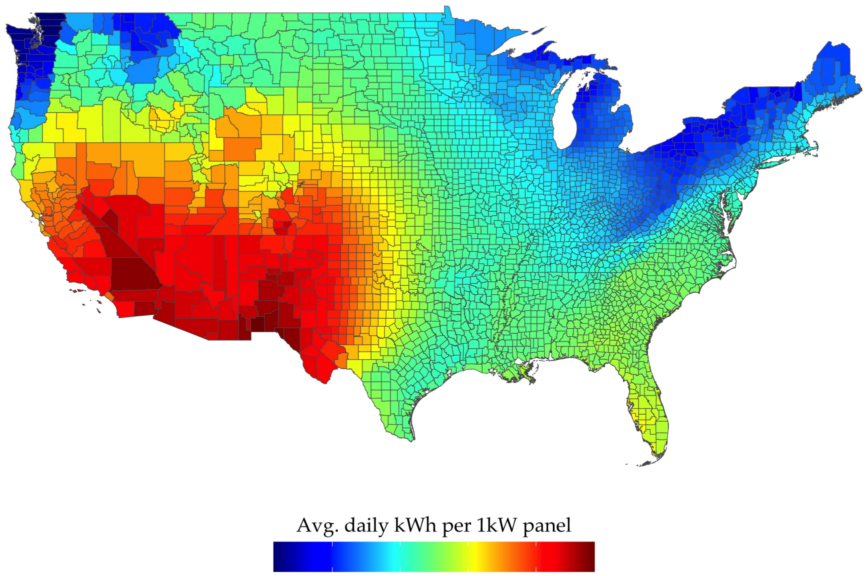
(a) Solar and Wind Share in Nameplate Capacity



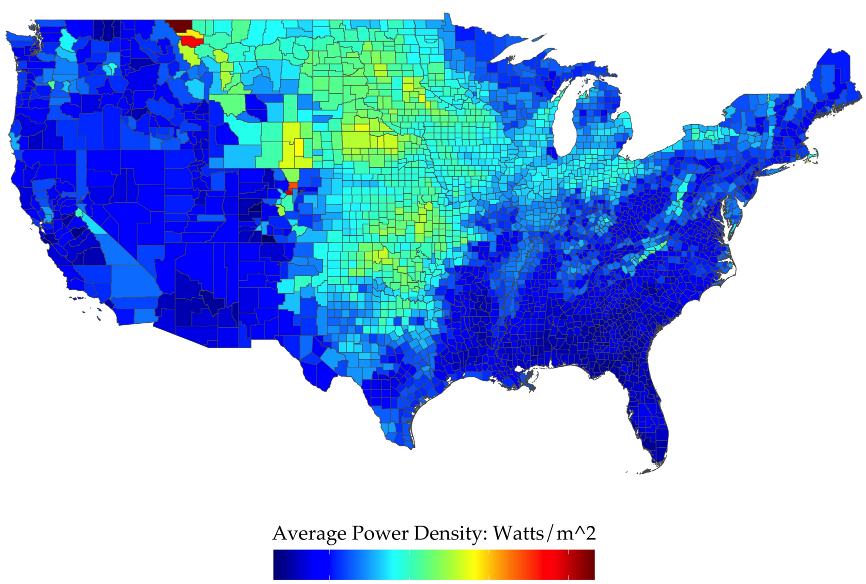
(b) Total Change In Capacity By Technology

Notes: Panel (a) of this figure shows the 12-month moving average of the monthly share of total electricity at the regional level coming from solar and wind. Panel (b) shows the change in nameplate capacity by technology. Data are from the US Energy Information Administration.

Figure 18: Solar and Wind Productivity Across Space



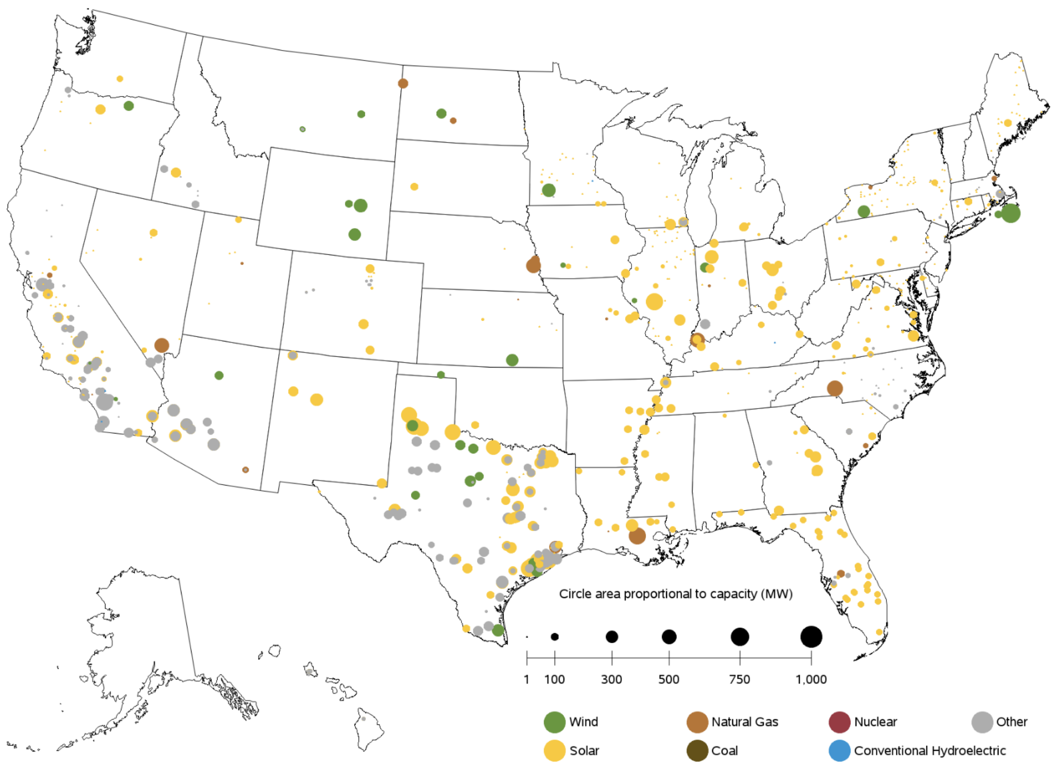
(a) Solar Potential



(b) Wind Potential

Notes: Panel (a) shows a measure of solar power potential, in average daily h produced by a 1 panel. Data is from the Global Solar Atlas. Panel (b) shows a measure of power output of a wind turbine, in average power density (watts per square meter), at a turbine height of 150 meters. Data is from the Global Wind Atlas. Units are US counties.

Figure 19: Energy Projects Currently Under Construction



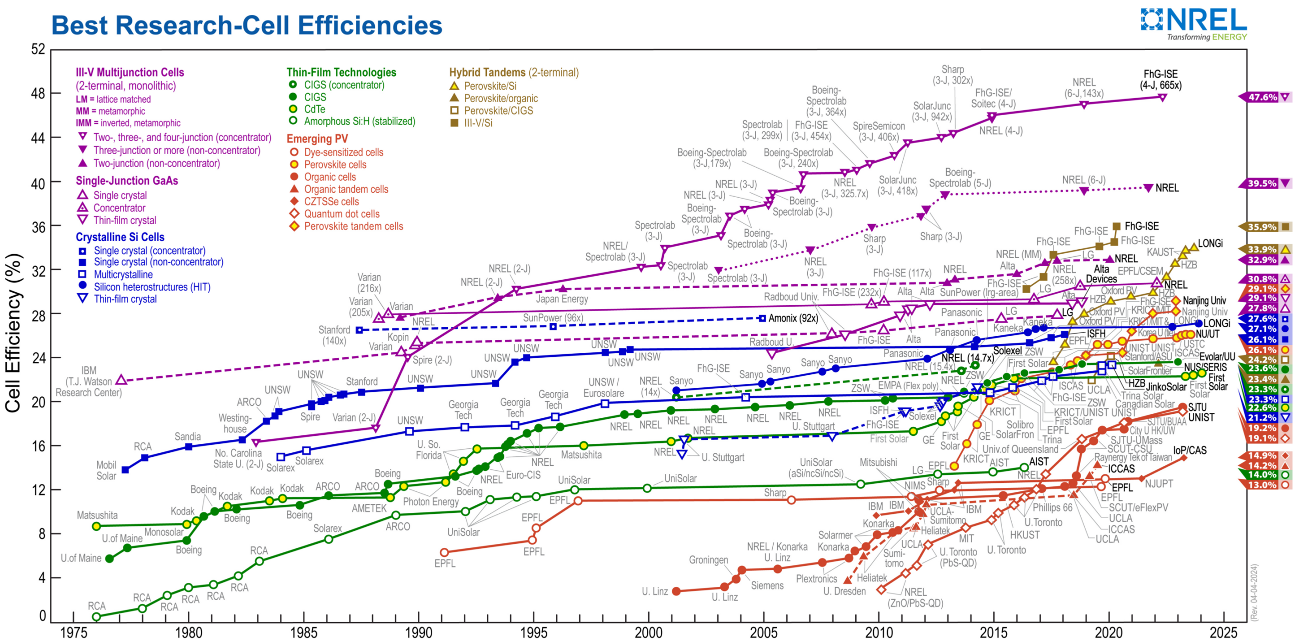
Notes: Figure shows the distribution of energy generation plants by type coming online between July 2024 and June 2025, and is a reproduction of a graph by the Energy Information Administration (EIA). Other (in gray) mainly refers to lithium-ion storage plants.

Table 1: Top 25 Exposed Industries

Industry	Value for Φ_s^E / Φ_s^L
Alumina refining and primary aluminum production	0.88
Federal electric utilities	0.86
Paperboard mills	0.69
Industrial gas manufacturing	0.60
Cement manufacturing	0.49
Dairy cattle and milk production	0.47
Pulp mills	0.42
Iron, gold, silver, and other metal ore mining	0.41
Other real estate	0.39
Other basic organic chemical manufacturing	0.36
Nonferrous metal (except aluminum) smelting and refining	0.35
Ground or treated mineral and earth manufacturing	0.35
Other basic inorganic chemical manufacturing	0.32
Petroleum refineries	0.27
Plastics material and resin manufacturing	0.26
Iron and steel mills and ferroalloy manufacturing	0.24
Copper, nickel, lead, and zinc mining	0.21
Plastics bottle manufacturing	0.19
Asphalt paving mixture and block manufacturing	0.19
Paper mills	0.19
Fertilizer manufacturing	0.19
Gasoline stations	0.19
Lime and gypsum product manufacturing	0.18
Wet corn milling	0.18
Glass and glass product manufacturing	0.18

Notes: This Table reports the top 25 exposed industries to electricity price falls, as measured by Φ_s^E / Φ_s^L,the ratio of expenditure on electricity to total labor payments are the sectoral level. The data is from the Bureau of Economic Analysis Input-Output Tables for 2017 using the detailed 402 industry breakdown.

Figure 20: NREL Cell Efficiency By Type



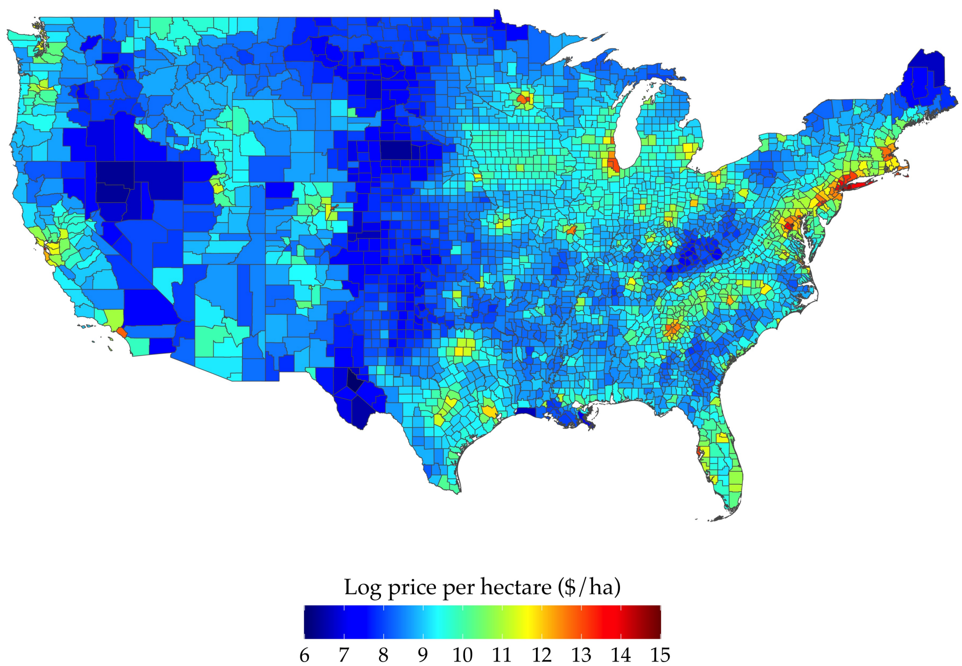
Notes: This Figure is a reproduction of a chart from the National Renewable Energy Laboratory, available here.

Table 2: Top 10 Large City Wage Increases

County	State	City	Wage Change (%)
San Bernardino	California	San Bernadino	4.01
Riverside	California	San Bernadino	3.84
Salt Lake	Utah	Salt Lake City	3.71
Orange	California	Los Angeles	3.5
Clark	Nevada	Los Vegas	3.46
Los Angeles	California	Los Angeles	3.29
King	Washington	Seattle	3.01
Santa Clara	California	Santa Clara	2.90
Tarrant	Texas	Dallas-Fort Worth	2.81
Bexar	Texas	San Antonio	2.78

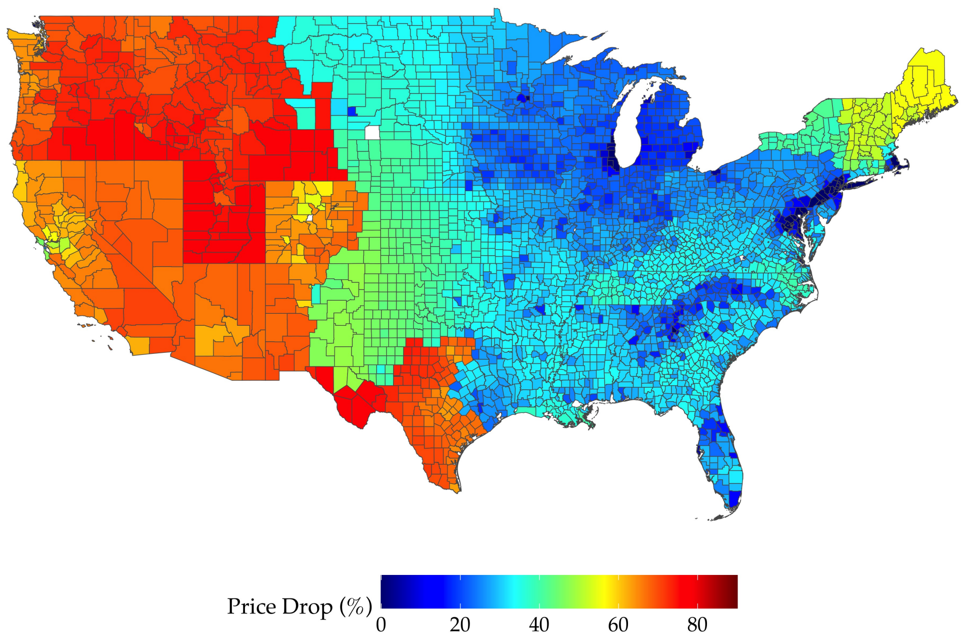
Notes: This Table reports the top 10 ten wage increases from the direct effect for counties with over 1 million employees.

Figure 21: Land Values in the US



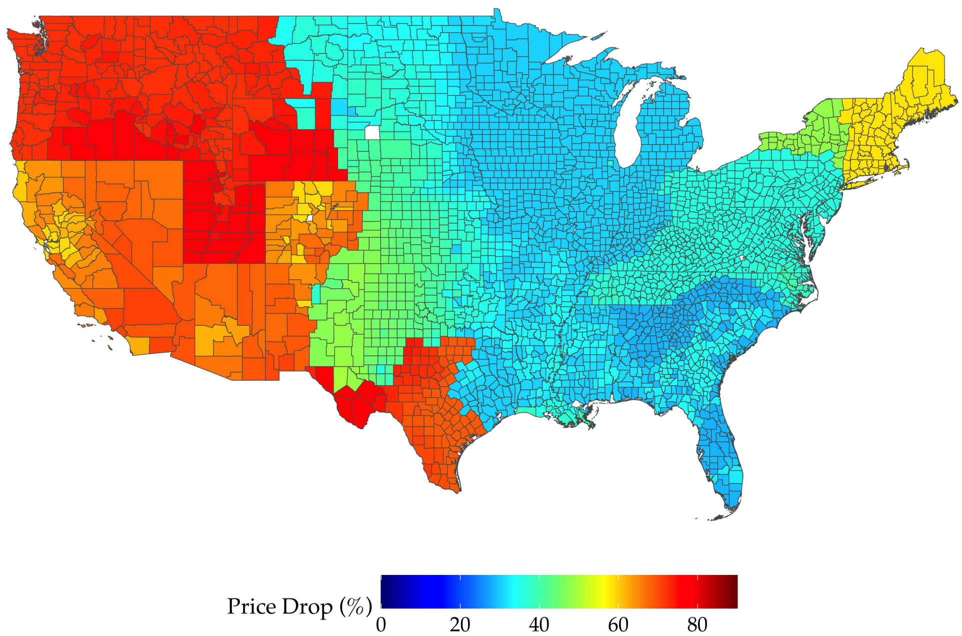
Notes: Figure plots estimates from Nolte (2020) for land prices in $ per hectare. Estimates are plotted on a log scale. Values are averaged at the county level.

Figure 22: Implied Wholesale Price Drops between 2024 and 2040



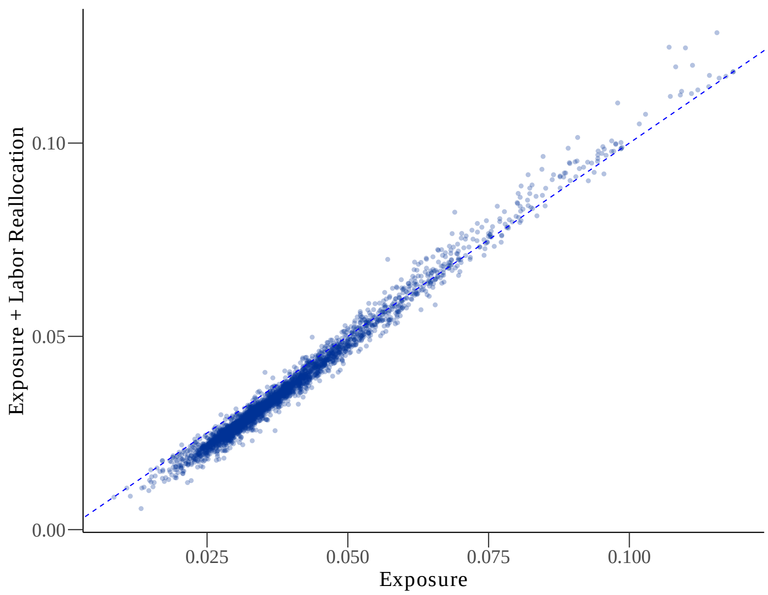
Notes: Figure shows the implied bound fall in wholesale prices between 2024 and using equation (2). Current wholesale prices in 2024 are collected from the Energy Information Administration. We use the average at the RTO level for 10 price hubs: Northwest, ISO-NE, NYISO, ERCOT, Southwest, CAISO, PJM, MISO, SPP, FRCC and SERC. Units are US counties.

Figure 23: Implied Wholesale Price Drops with Mild Integration



Notes: Figure shows the implied bound fall in wholesale prices between 2024 and using equation (2), under the assumption that the maximum price is $25 per MWh. Current wholesale prices in 2024 are collected from the Energy Information Administration. We use the average at the RTO level for 10 price hubs: Northwest, ISO-NE, NYISO, ERCOT, Southwest, CAISO, PJM, MISO, SPP, FRCC and SERC. Units are US counties.

Figure 24: Incorporating Labor Reallocation



Notes: Figure shows the calculated direct exposure measures Ω_l from equation (8) at the county level, against the sum of Ω_ℓ and the labor reallocation term in (8). The blue dashed line is the 45-degree line.

B A Model Of Trade, Power and Production

Consider a model of production and trade wherein agents live in a number of discrete locations ℓ. Suppose agents have preferences over an aggregator of sectoral goods given by

$$C = U(\{C_s\}_s). \tag{11}$$

Workers have preferences over the final consumption aggregator and residential housing h. The price of this aggregator is chosen as the numeraire. Each period, an individual worker j of labor type chooses a location ℓ, sector s, and quantities of housing (h) and the final good (c) to solve the following utility-maximization problem:

$$\max_{\ell}\{\vartheta^j_\ell \mathbb{E}_{\vartheta_s} \max_{s,h,c}\{V^W(c,h)\vartheta^j_s\}\} \quad \text{subject to } \; m^h_\ell h + c = w_{\ell s}, \tag{12}$$

where $V^W(c,h)$ is concave and continuously differentiable, and m^h_ℓ is the rental rate on residential land in location ℓ. ϑ^j_ℓ and ϑ^j_s are sectoral preference shocks that give rise to smooth labor supply curves, discussed further in Section (B.5). Time is discrete, but for the moment we suppress the time index t.

B.1 Firms

Firms produce a unique differentiated variety i. Firm i located in location ℓ and sector s produce with

$$y_i = z_i F_{\ell s}(l, e, \boldsymbol{x})$$

where l is labor, e is electricity and $\boldsymbol{x}$ is a vector of intermediate inputs. z_i is an index of firm level TFP. Note that the production function $F_{\ell s}(\cdot)$ may be location- and sector-specific, incorporating exogenous local productivity differences and endogenous agglomeration forces, as long as these are taken as given by the firm.

Firms need to pay an entry cost, defined by $g_{\ell s}(l,e) = 1$, and after entry they draw their productivity from an exogenous distribution $\Psi_{\ell s}(z)$, which may depend on location and sector. They exit at constant rate ξ. We assumed g is constant returns to scale. The resulting entry cost is denoted $G_{\ell s}(w_{\ell s}, p^{\mathcal{E}}_\ell)$.

We suppose there are no trade costs, and that intermediate inputs enter in a single aggregate input for all firms in the same way (though they may use this with different intensity).

That is, we suppose

$$y_i = z_i F_{\ell s}(l, e, X),$$

where

$$X = f(\boldsymbol{x})$$

is a symmetric aggregator for all firms. We further assume it takes the same form as final goods aggregation, so that both the intermediates price and the final good price serve as the numeraire. Cost minimization for a given level of output y allows us to write a cost function

$$C_{\ell s}(y; z) = z^{-1} y v_{\ell s}(w_{\ell s}, p_{\ell}^{\mathcal{E}}, y),$$

where v is the average unit cost function.

The pricing decision leads to a concave revenue function $R_s(y) = D_s r_s(y)$, where D_s is an aggregate sectoral demand shifter. Notice that this is not an innocuous assumption. For example, in our context it implies the absence of trade costs or differential wedges across sectors. Nevertheless, it does allow for a broad class of demand functions. Consider for example single-aggregator demand functions such as those considered by Arkolakis et al., 2012; Matsuyama and Ushchev, 2017,

$$y_s(p) = d_s\left(\frac{p}{P_s^*}\right),$$

where P_s^* is an aggregator function, p is the firm's price and $d_s(.)$ is a demand function that is strictly decreasing in its argument. The revenue function can then be written as

$$R_s(y) = py = P_s^* d_s^{-1}(y)\, y = d_s^{-1}(y)\, y \times P_s^* = r_s(y) \times D_s.$$

where $D_s \equiv P_s^*$ and $r_s(y) \equiv d_s^{-1}(y)\, y$. The CES demand is a special case of this class with

$$y_s(p_s) = p_s^{-\sigma_s} \times \frac{Y}{P_s^{1-\sigma_s}},$$

where Y is total income and P_s is the CES aggregator.

B.2 Capitalists

There is a population of capitalists who own the firms, local land, solar capital and intermediates goods. They care only about consumption C_t^K, with the same aggregation over sectors as in (11), and have intertemporal preferences given by

$$V^K = \sum_{t=0}^{\infty} \beta^t v(C_t^K). \tag{13}$$

We suppose that they can invest in new firms, and the vector of intermediates which depreciate at rate δ_s and have rental rate m_{st}. The stock of each intermediate is denoted X_{st}. They receive the profits from all the firms and land. Their budget constraint is

$$\begin{aligned} &C_t^K + \sum G_{\ell s}(w_{\ell st}, p_{\ell t}^{\mathcal{E}})(N_{\ell st+1} - (1-\xi)N_{\ell st}) \\ &+ \sum_{\ell} Q_{t+1}(S_{\ell t+1} - (1-\delta^S)S_{\ell t}) = \sum_{s}\sum_{l} \Pi_{s\ell t} + \sum_{l} p_{\ell t}^{\mathcal{E}} \theta_\ell S_{\ell t+1} + \sum m_{\ell t}^h H, \end{aligned} \tag{14}$$

where $N_{\ell st}$ is the number of firms in location ℓ and sector s at time t, $\Pi_{\ell st}$ is the profits they make, and H is the supply of residential land (in fixed supply).

Free entry into firm creation requires that the return on creating firms is equal to the return on investing in the intermediates, so that

$$G_{\ell s}(w_{\ell st}, p_{\ell t}^{\mathcal{E}}) = \sum_{\tau=0}^{\infty} R_{t\to t+\tau}(1-\xi)^\tau \left(\int_z \left[\max_y D_{st+\tau} r(y) - C_{\ell st+\tau}(y; w_{\ell st+\tau}, p_{\ell t+\tau}^{\mathcal{E}}, z) \right] d\Psi_{\ell s}(z) \right). \tag{15}$$

where $R_{t\to t+\tau}$ is the common real cumulative return on assets (which must be common for all assets in equilibrium).

Solar capital $S_{\ell t}$ provides θ_ℓ units of electricity per period. It can be bought by converting units of the final good into capital at rate $1/Q_t$, which we take to be an exogenous parameter. It depreciates at rate δ^S.

B.3 Definition of Equilibrium

An equilibrium is a time path for of wages $w_{\ell st}$ in each location-sector, a path for sectoral intermediates prices P_{st}, rental rates on residential land $\{m_{\ell t}^h\}$, an allocation of consumption C_t^K for capitalists, stocks of workers in each location-sector $L_{\ell st}$, numbers of firms in each location $N_{\ell st}$, stocks of solar capital $S_{\ell t}$,such that given a price for solar capital Q_t,

1. Workers solve their problem (12) statically,

2. Capitalists maximize (13) subject to (14),

3. The free entry condition (15) holds,

4. All markets clear.

A steady-state equilibrium is one in which all prices and allocations are constant through time.

B.4 General Equilibrium Price Changes

Proof of Proposition 1. In a steady state of the model with no growth, the free-entry condition can be written

$$\begin{aligned} G_{\ell s}(w_{\ell s}, p_\ell^{\mathcal{E}}) &= \kappa \int \pi_{\ell s}(z) d\Psi_{\ell s}(z) \\ &= \kappa \int \max_y \left[D_s r_s(y) - z^{-1} y v(w_{\ell s}, p_\ell^{\mathcal{E}}, y) \right] d\Psi_{\ell s}(z), \end{aligned}$$

where κ is a proportional constant equal to $(\beta+1)/(\beta\xi+1)$, and $G_{\ell s}(w_{\ell s}, p_\ell^{\mathcal{E}})$ is the optimized entry cost.

We derive the first order response of local factor prices to a decrease in electricity prices as follows. By the envelope theorem, we have

$$\frac{\partial \pi_{\ell s}(z, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}} = -z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}}, \qquad \frac{\partial \pi_{\ell s}(z, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}} = -z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}},$$

where y is understood to be optimal output at the given vector of factor prices. In addition, when sectoral demand changes the effect on profit is given by

$$\frac{\partial \pi_{\ell s}(z)}{\partial D_s} = r_s(y).$$

Totally differentiating the free-entry condition and using these expressions yields

$$\begin{aligned} \frac{\partial G_{\ell s}}{\partial w_{\ell s}} dw_{\ell s} + \frac{\partial G_{\ell s}}{\partial p_\ell^{\mathcal{E}}} dp_\ell^{\mathcal{E}} = \kappa \int \Bigg[& r_s(y) D_s dlog D_s \\ & - z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}} dw_{\ell s} - z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}} dp_\ell^{\mathcal{E}} \Bigg] d\Psi_{\ell s}(z). \end{aligned} \tag{16}$$

The intermediate bundle is the numeraire and so receives no price change. We can also write the free-entry condition using Euler's theorem and Shephard's Lemma as

$$\frac{\partial G_{\ell s}}{\partial p_\ell^{\mathcal{E}}} w_{\ell s} + \frac{\partial G_{\ell s}}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} = \kappa \int \left[r_s\left(y\right) D_s - z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}} w_{\ell s} - \right. \\ \left. z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} - z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial P} \right] d\Psi_{\ell s}(z), \qquad (17)$$

where P is the price of the intermediate bundle/final good, and is the numeraire so equals 1. Use this last expression to rearrange and obtain

$$\int r_s\left(y\right) D_s d\Psi_{\ell s}(z) = \frac{\partial G_{\ell s}}{\partial w_{\ell s}} w_{\ell s} + \frac{\partial G_{\ell s}}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} \\ + \kappa \int \left[z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_{\ell s})}{\partial w_{\ell s}} w_{\ell s} + z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} + z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial P} \right] d\Psi_{\ell s}(z),$$

and insert this into (16) to get

$$\left[\frac{\partial G_{\ell s}}{\partial w_{\ell s}} w_{\ell s} + \kappa \int z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}} w_{\ell s} d\Psi_{\ell s}(z) \right] d\log w_{\ell s} + \left[\frac{\partial G_{\ell s}}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} + \int z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} d\Psi_{\ell s}(z) \right] d\log p_{\ell s} \\ = \left[\frac{\partial G_{\ell s}}{\partial w_{\ell s}} w_{\ell s} + \kappa \int z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}} w_{\ell s} d\Psi_{\ell s}(z) + \frac{\partial G_{\ell s}}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} + \int z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial p_\ell^{\mathcal{E}}} p_\ell^{\mathcal{E}} d\Psi_{\ell s}(z) + \int z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial P} d\Psi_{\ell s}(z) \right] d\log D_s.$$

Now note that total expenditure on labor (inclusive of both entry costs and variable costs) is

$$\Phi_{\ell s}^L \equiv N_{\ell s} \left[\frac{\partial G_{\ell s}}{\partial w_{\ell s}} w_{\ell s} + \kappa \int z^{-1} y \frac{\partial v_{\ell s}(y, w_{\ell s}, p_\ell^{\mathcal{E}})}{\partial w_{\ell s}} w_{\ell s} d\Psi_{\ell s}(z) \right],$$

with a similar expression for $\Phi_{\ell s}^E$ and $\Phi_{\ell s}^X$, where $N_{\ell s}$ is the number of firms in location ℓ and sector s. Rearranging gives us

$$d\log w_{\ell s} = -\frac{\Phi_{\ell s}^E}{\Phi_{\ell s}^L} d\log p_\ell^{\mathcal{E}} + \frac{\Phi_{\ell s}^E + \Phi_{\ell s}^L + \Phi_{\ell s}^X}{\Phi_{\ell s}^L} d\log D_s,$$

where $\Phi_{\ell s}^E$ is total local sectoral expenditure on electricity, Φ_ℓ^L is expenditure on labor and $\Phi_{\ell s}^X$ is local expenditure on intermediates.

B.5 Labor Supply Elasticities Across Sectors

Here we put structure on worker preferences, and derive their resulting labor supply curves. We first assume that workers' preferences over consumption and housing are Cobb-Douglas, and the weight on housing is α.

We assume that workers draw their idiosyncratic preference shocks for each location and sector from Frechet distributions with scale parameters A_ℓ and $B_{\ell s}$ respectively (for location, and sector conditional on location), and shape parameters ϱ and η. The fraction of workers deciding to live in location ℓ,λ_ℓ, and for working in sector s conditional on choosing to live in location ℓ, $\mu_{\ell s}$, are given by

$$\lambda_\ell = \frac{A_\ell (r_\ell^{-\alpha} \Psi_\ell)^\varrho}{\sum_{\ell'} A_{\ell'} (r_{\ell'}^{-\alpha} \Psi_\ell)^\varrho} \qquad \mu_{\ell s} = \frac{B_{\ell s}(w_{\ell s})^\eta}{\sum_{s'} B_{\ell s'}(w_{\ell s'})^\eta},$$

where $\Psi_\ell \equiv (\sum_s B_{\ell s}(w_{\ell s})^\eta)^{\frac{1}{\eta}}$. From this expression, we can derive the change in sectoral employment shares as

$$d \log \mu_{\ell s} = \eta d \log w_{\ell s} - \eta \sum \mu_{ls} d \log w_{\ell s}.$$

Then we have

$$\sum_s \frac{\mu_{\ell s} w_{ls}}{\sum_s \mu_{\ell s} w_{\ell s}} d \log \mu_{\ell s} = \eta \sum_s \frac{\mu_{\ell s} w_{ls}}{\sum_s \mu_{\ell s} w_{\ell s}} d \log w_{\ell s} - \eta \sum_s \mu_{ls} d \log w_{\ell s}.$$

B.6 General Equilibrium Aggregate Demand Effects

We move to consider the aggregate demand effects in the model above by making some further parametric assumptions. Assume

1. There are no trade costs
2. There is no intermediate usage
$$F_{\ell s}(l, e, X) = F_{\ell s}(l, e)$$
3. The utility function for final demand is Cobb-Douglas, so that
$$U(\{C_s\}_s) = \prod_{s=1}^{S} C_s^{\gamma_s}$$
4. Aggregation within sectors is CES with elasticity of substitution σ_s
5. The entry cost is denominated in units of the final good, so that the cost of entry is equal to $\bar{g}$ and the same everywhere

6. Production functions are constant returns to scale

In this case it can be shown that the sectoral demand shifter on firm profits is given by

$$D_s = \frac{\gamma_s Y}{P_s^{1-\sigma_s}},$$

where Y is aggregate income, given by

$$Y = \sum_{\ell}\sum_{s} w_{\ell s} L_{\ell s} + \sum_{\ell}\sum_{s} p_{\ell}^{\mathcal{E}} E_{\ell s} + \sum_{\ell}\sum_{s} N_{ls} \int \pi_{\ell s}(z) d\Psi_{\ell s}(z), \tag{18}$$

or the sum of labor income, electricity sales and firm profits. For notational convenience, call aggregate profits $\Pi \equiv \sum_{\ell}\sum_{s} N_{ls} \int \pi_{\ell s}(z) d\Psi_{\ell s}(z)$. In turn, the price index is given by

$$P_s^{1-\sigma_s} = \sum_{\ell} N_{ls} \int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z),$$

where $p_{\ell s}(z)$ is the intermediate good price for a firm with productivity z in location ℓ and sector s. As such,

$$d\log D_s = d\log Y - d\log P_s^{1-\sigma_s},$$

with the additional restriction that

$$\sum \gamma_s d\log P_s = 0,$$

by choice of the numeraire. Consider first the change in the sectoral price index.

$$\begin{aligned} d\log P_s^{1-\sigma_s} = & \frac{\sum_{\ell} N_{ls} \int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z) d\log N_{\ell s}}{\sum_{\ell} N_{ls} \int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z)} \\ & + (1-\sigma) \frac{\sum_{\ell} N_{ls} \int p_{\ell s}(z)^{1-\sigma} \left(\frac{w_{\ell s} l_{\ell s}(z)}{w_{\ell} l_{\ell s}(z) + p_{\ell}^{\mathcal{E}} e_{\ell s}(z)} d\log w_{\ell s} + \frac{p_{\ell}^{\mathcal{E}} e_{\ell s}(z)}{w_{\ell} l_{\ell s}(z) + p_{\ell}^{\mathcal{E}} e_{\ell s}(z)} d\log p_{\ell}^{\mathcal{E}} \right) d\Psi_{\ell s}(z)}{\sum_{\ell} N_{ls} \int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z)}. \end{aligned}$$

where the second term invokes Shepard's Lemma. If production functions are constant returns to scale, then cost shares do not vary with firm level efficiency z, and this can be written as

$$d\log P_s^{1-\sigma_s} = \frac{\sum_\ell N_{ls}\int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z) dlog N_{\ell s}}{\sum_\ell N_{ls}\int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z)}$$

$$+ (1-\sigma)\frac{\sum_\ell N_{ls}\int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z)\left(\frac{\Phi_{ls}^L}{\Phi_{ls}^L+\Phi_{ls}^E} d\log w_{\ell s} + \frac{\Phi_{ls}^L}{\Phi_{ls}^L+\Phi_{ls}^E} d\log p_\ell^{\mathcal{E}}\right)}{\sum_{\ell'} N_{l's}\int p_{\ell' s}(z)^{1-\sigma} d\Psi_{\ell' s}(z)}.$$

Note that market clearing in the output market has

$$\frac{\sigma}{\sigma-1}(w_{\ell s}L_{\ell s} + p_\ell^{\mathcal{E}} E_{\ell s}) = \frac{N_{ls}\int p_{\ell s}(z)^{1-\sigma} d\Psi_{\ell s}(z)}{\sum_{\ell'} N_{l's}\int p_{\ell' s}(z)^{1-\sigma} d\Psi_{\ell' s}(z))}\gamma_s Y.$$

So we can rewrite this as

$$d\log P_s^{1-\sigma_s} = \frac{\sigma}{\sigma-1}\sum_\ell \frac{w_{\ell s}L_{\ell s} + p_\ell^{\mathcal{E}} E_{\ell s}}{\gamma_s Y} d\log N_{\ell s}$$

$$-\frac{1}{\sigma}\sum_\ell \frac{w_{\ell s}L_{\ell s} + p_\ell^{\mathcal{E}} E_{\ell s}}{\gamma_s Y}\left(\frac{\Phi_{\ell s}^L}{\Phi_{\ell s}^L+\Phi_{\ell s}^E} dlog w_{\ell s} + \frac{\Phi_{\ell s}^L}{\Phi_{\ell s}^L+\Phi_{\ell s}^E} d\log p_\ell^{\mathcal{E}}\right).$$

Now the free entry condition requires expected profit to equal the entry cost $\bar{g}$, so that

$$\kappa\int_z (p_{\ell s}(z) - v_{\ell s}(w_{\ell s}, p_\ell^{\mathcal{E}}))y_{\ell s}(z) d\Psi_{\ell s} = \bar{g}$$

implies

$$\frac{1}{\sigma}\mathbb{E}_{\ell s}[sales] = \bar{g}/\kappa,$$

given the optimal pricing formula with CES demand. In addition, total sales equaling factor income and profits requires

$$N_{\ell s}\mathbb{E}_{\ell s}[sales] = \frac{\sigma}{\sigma-1}\left(w_{\ell s}L_{\ell s} + p_\ell^{\mathcal{E}} E_{\ell s}\right),$$

so that

$$N_{\ell s} = \frac{1}{(\sigma-1)}\kappa\bar{g}^{-1}\left(w_{\ell s}L_{\ell s} + p_\ell^{\mathcal{E}} E_{\ell s}\right).$$

As such

$$
\begin{aligned}
d\log N_{\ell s} &= d\log\left(w_{\ell s}L_{\ell s} + p^{\mathcal{E}}_{\ell}E\right). \\
&= \left(\frac{\Phi^L_{\ell s}}{\Phi^L_{\ell s}+\Phi^E_{\ell s}}\left(d\log w_{\ell s} + d\log L_{\ell s}\right) + \frac{\Phi^L_{ls}}{\Phi^L_{ls}+\Phi^E_{ls}}\left(d\log p^{\mathcal{E}}_{\ell} + d\log E_{\ell s}\right)\right)
\end{aligned}
$$

Similarly, with profits being a fixed fraction of revenue under the CES demand structure, we also have from equation (18)

$$
\begin{aligned}
d\log Y = \sum_{\ell}\sum_{s} \frac{\sigma/(\sigma-1)\left(w_{\ell s}L_{\ell s}+\bar{p}_l E\right)}{Y}&\left(\frac{\Phi^L_{\ell s}}{\Phi^L_{\ell s}+\Phi^E_{\ell s}}\left(d\log w_{\ell s}+d\log L_{\ell s}\right)\right. \\
&\left.+\frac{\Phi^L_{\ell s}}{\Phi^L_{\ell s}+\Phi^E_{\ell s}}\left(d\log p^{\mathcal{E}}_{\ell}+d\log E_{\ell s}\right)\right).
\end{aligned}
$$

C Price Bounds for Wind Power

We conduct our analysis in the main text using estimates for firmed solar power, as we believe it is likely to be the dominant technology in a renewable dominated grid, owing both to its rapid cost falls and a relatively unconstrained local potential in the analysis above. However, wind power has a significantly different geography of potential (see Figure 18). In particular, wind power is strong in some places where solar is weak; in particular in the rustbelt of Ohio, Michigan, and upstate New York. It is worth asking how our estimates of price drops would change if we extend the analysis to consider wind power.

Wind power is somewhat more involved to model than solar. The exact capacity factors depend on the turbine model used, which are currently quite heterogeneous, and difficult to project out to the future. As such, we take the following approach. We gather data for current capacity factors of different turbine classes and wind power density at 100m from the Global Wind Atlas. We use this data to form an estimate of wind power output at the local level.

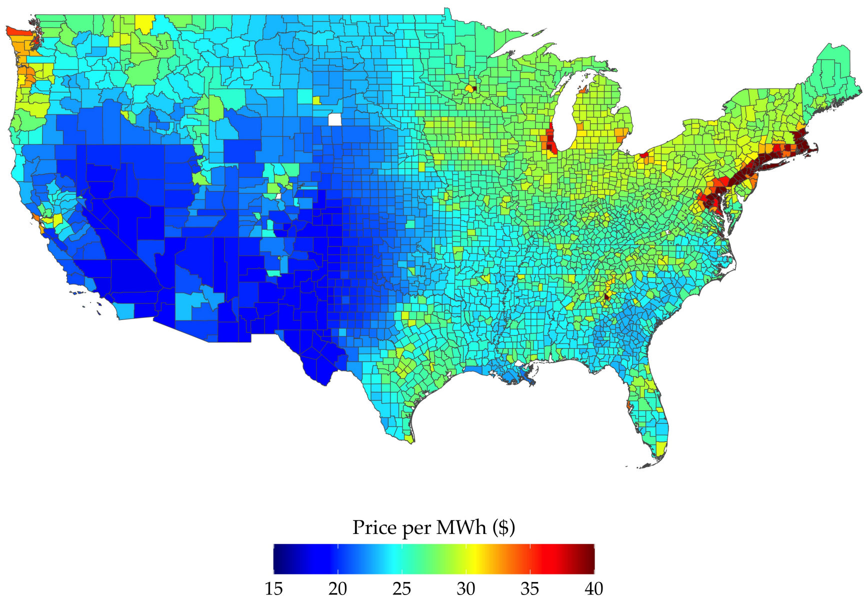
We then assume that the capital cost of turbines continues to track the rate of decline seen in the Levelized Cost of Energy database for major countries from the International Renewable Energy Database, at -4% a year, and project this out to 2040. In addition, we assume that land costs remain the same, currently accounting for 2% of the levelized cost of wind in the United States using data from the NREL (Stehly et al., 2023). As we do for solar, we scale land costs depending on local land prices, and assume a long-run cost of financing of 5%. Lastly, we assume a thirty year life span, and a depreciation rate of 2%.

Together, this allows us to develop the price bound in (2) for wind. The results are plotted in Figure 25. Wind turns out to imply a lower cost bound than solar in select locations. In particular, the Rustbelt as a whole sees lower prices coming from wind than solar. However, for much of the country it is the solar bound that dominates, which can be seen by taking the minimum of the two bounds and plotting them in Figure 26.

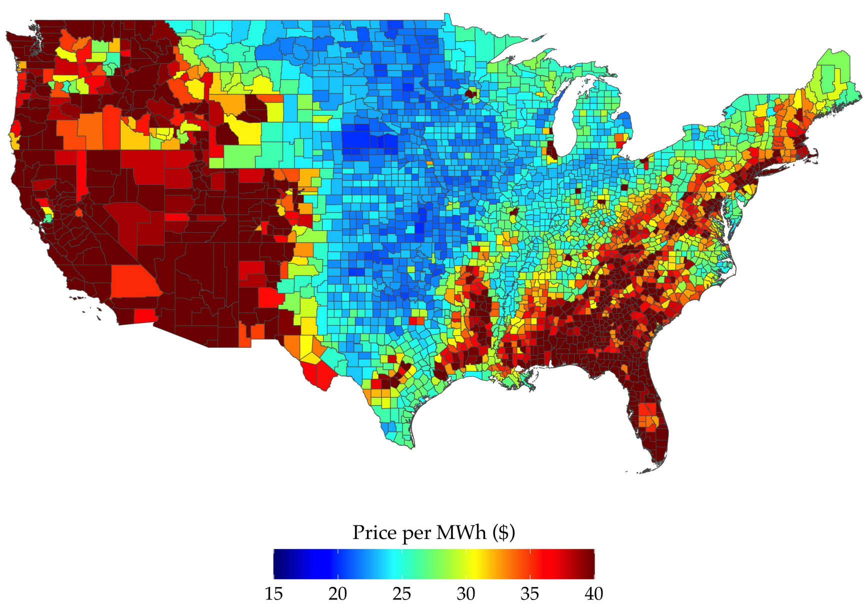
For this exercise we do not add storage costs to wind, as we do for solar, as the intermittency cost of wind energy is somewhat less pronounced, and likely to be further mitigated by the high amounts of storage required for solar in a renewable-dominated grid. Adding the cost of 8 hours of storage assumed above to the capital cost of wind in 2040 raises the long run price bounds below by around 20% across the US.

We are hesitant to include this analysis in the main body for a simple reason: land constraints for wind are far more severe than for solar. The NREL estimates that total developable capacity for wind is less than a tenth of the 83 terrwatts of solar potential. The land requirement per megawatt is also an order of magnitude greater, with many of the best sites in the US already developed. This makes us doubt the applicability of the free entry condition in every county, whereas for firmed solar we feel this is a much more reasonable assumption.

Figure 25: Price Maps Using Solar and Wind Technology



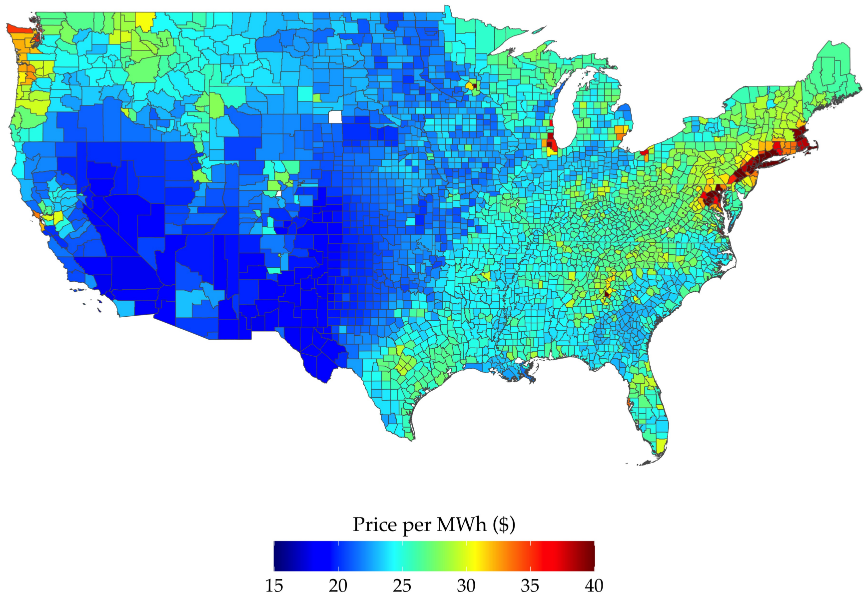
(a) Solar



(b) Wind

Notes: Panel (a) shows the price bound from equation (2) using data for firmed solar, and Panel (b) does the same using data for wind energy.

Figure 26: Minimum Of Solar and Wind Price Bound



Notes: This Figure presents the minimum implied price bound at the local level from the subfigures of Figure (25).