Effects of the Inflation Reduction Act on Renewable Energy Manufacturing and Development Costs and Deployment

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Abstract

In 2022, the U.S. government passed unprecedented climate and social equity legislation – the Inflation Reduction Act (IRA) – designed to incentivize renewable and low-carbon energy deployment, promote domestic supply chains, and address labor and environmental justice concerns. In this study, we model the effects of the IRA on renewable energy manufacturing and development costs and deployment. We find that tax credits to encourage expansion of U.S. manufacturing are likely to generate comparative cost advantages for domestically-produced components across the utility-scale solar and wind supply chain relative to imported components. We also show that the *bonus* rate tax credits for renewable developers will decrease the U.S. average levelized cost of utility-scale solar (26-65%), land-based wind (43-61%), and offshore wind (16-19%) projects, even when accounting for uncertainty in inflation, domestic content of renewable components, and pass-through of component cost savings associated with the manufacturing tax credit to developers. Additional tax credits available to developers meeting *energy community* and *domestic content share* requirements further reduce costs for qualifying projects. We find that tax credits for renewable developers collectively have the potential to substantially increase the deployment of renewable infrastructure, drive demand for domestically-produced components, and foster workforce access, higher wages, and the retention of workers. A large share of renewable investments and capacity may flow to disadvantaged communities (27 and 46% for utility-scale solar and land-based wind projects, respectively), although inframarginal changes in development costs associated with place-based incentives, such as the *energy community* tax credit, may be insufficient to influence project siting decisions, given transmission constraints, spatial proximity to electricity demand, and renewable resource potential.

Keywords

solar, wind, tax credits, manufacturing, energy policy, Inflation Reduction Act

1 Introduction

Net emissions of greenhouse gases from human activities must reach zero to stabilize the global mean temperature [1]. In 2021, the Biden administration committed to reduce U.S. greenhouse gas emissions to 50%–52% below 2005 levels by 2030 and net-zero emissions by mid-century [2,3]. In order to close the gap between stated ambition and action, the U.S. government passed unprecedented climate legislation – the Inflation Reduction Act (IRA) of 2022 [4]. Multiple independent analyses find that the IRA could induce economy-wide emissions reductions between 33-41% below 2005 levels by 2030 and 43-53% below 2005 levels by 2035, largely associated with accelerated deployment of wind and solar [5–8].

The IRA was designed to incentivize investment in clean energy sources and electrification, improve energy efficiency, strengthen domestic supply chains, and address labor and environmental justice concerns, through a package of tax credits, grants, rebates, and loan programs [4]. Certain federal investments associated with the IRA must also comply with the Justice40 Initiative outlined in an executive order issued by the White House in 2021 [2]. The goal of the Justice40 Initiative is to ensure that at least 40% of benefits (e.g., air quality reductions, employment, local tax revenues) flow to disadvantaged communities defined based on environmental, climate, socioeconomic, and other burdens by the White House U.S. Council on Environmental Quality [9]. The IRA appropriates $110 billion in direct spending on climate-related programs over ten years, and the Congressional Budget Office and Joint Committee on Taxation estimated that tax credit programs will decrease government revenues by $269 billion over ten years (2022-2031) [10]. Outlays for the tax credits could be materially larger, given that the actual spending is not constrained by a fixed budget nor subject to further appropriations, and in many cases, provisions persist beyond a decade.

The IRA contains several provisions targeted at renewable energy, including extending and increasing the value of the production tax credit (PTC) and investment tax credit (ITC) incentives (including sections 45, 45Y, 48, and 48E) to reduce costs for renewable energy project developers. The IRA extends full credit eligibility to projects commencing construction before the end of 2033 or the year after U.S. power sector emissions fall to 25% of 2022 levels, whichever comes *later,* providing long-term investment certainty for clean energy investors [11,12]. The IRA also facilitates the monetization of tax credits by project owners by making direct payments available to non-taxable entities and allowing taxable entities to transfer some or all of the tax credit in any year to any other entity with business tax liability, an important provision given that developers rarely have sufficient propensity to fully absorb the large tax credits directly.

New and existing renewable energy projects can qualify for either a *base* rate (i.e., a PTC of 0.55 per cents per kilowatt-hour (kWh) in 2022$ or a 6% ITC), or a *bonus* rate that is equivalent to five times the *base* rate (2.75 cents/kWh PTC and 30% ITC) [11,12]. For a project to qualify for the bonus rate, the following labor requirements must be met: 1) laborers and mechanics must be paid prevailing wage rates for construction, alteration, or repair work, and 2) a certain percentage of construction work must be performed by qualified apprentices [13]. By increasing compensation and providing workforce training opportunities via apprenticeships, the labor requirements have the potential to ease labor supply constraints that are already present in renewable industries [14] as well as better retain the renewable energy workforce [15].

In addition, renewable energy projects can qualify for tax credit adders that increase the value of the PTC by 10% or the value of the ITC by 10 percentage points if renewable projects meet *domestic content* requirements and/or qualify as an *energy community*. The two adders can be combined if projects qualify for both. To qualify for the *domestic content* adder, developers are required to utilize U.S. steel and iron and procure manufactured products (e.g., wind turbines) meeting minimum domestic content shares [16]. The intention of the domestic content adder is to induce demand for domestically-produced materials and products, which has the potential to spur onshoring of manufacturing capacity, moderate supply chain risks that could impede renewable deployment, and generate local economic benefits. To qualify for the *energy community* adder, a project must be located in an "energy community" which is defined as a 1) brownfield site, 2) census tract (or an adjoining tract) where a coal-fired power plant or coal mine has recently closed, or 3) metropolitan or non-metropolitan statistical area where a minimum portion of employment or local tax revenues were historically linked to coal, oil, or natural gas activities and unemployment rates meet or exceed the national average in the preceding year [17]. The energy community adder has the potential to moderate economic losses associated with declining fossil fuel production, transportation, processing and use, as well as direct investment in areas that have historically been underserved and overburdened.

In addition to incentives for developers, the IRA establishes a new advanced manufacturing production tax credit (AMPC, section 45X) for domestic producers of wind, solar, and battery components and critical minerals [11,12]. The 45X tax credit is a supply-side policy instrument to spur onshoring or reshoring of manufacturing, complementing the domestic content adder to the PTC and ITC that drive demand for U.S. manufactured products and materials. In addition, the advanced energy project credit (section 48C) establishes a 30% investment tax credit to defray capital expenditures at qualified clean energy manufacturing facilities, although funding for this tax credit is limited to $10 billion from 2023-2032. For more detailed information regarding policy provisions, refer to Supplemental Information (SI) Section 1.1.

There are many interacting incentives in the IRA that are intended to spur investment in renewable generation capacity and domestic manufacturing. Here, we assess the impact of provisions in the IRA that will directly affect costs of renewable energy manufacturing, project development, and construction, including the PTC and ITC (sections 45, 45Y, 48, and 48E) and the advanced manufacturing production credit (section 45X). Specifically, we analyze the impacts of the IRA on the cost of domestically-produced components (relative to imports) across the utility-scale solar and wind supply chains. In addition, we model various combinations of tax credits for developers and compare of the impact on the levelized cost of land-based wind, offshore wind, and utility-scale solar across several policy scenarios, accounting for uncertainty in domestic content shares, capacity factors, and other spatially-explicit cost factors. We additionally model the potential geospatial distribution of renewable deployment induced by the IRA.

2 Methods

2.1 Baseline technology costs

We estimate baseline component, installation, and operating and maintenance (O&M) costs for 2021, absent the IRA incentives, as well as costs for U.S. manufactured and imported components across the solar photovoltaic (PV) supply chain (i.e., polysilicon, wafers, cells, PV modules, inverters) and wind supply chain (i.e., blades, nacelles, towers).

We assume that the baseline average global cost of PV modules in 2021 is \$0.26/W_{dc} (excluding shipping costs), the reported cost of production in China, which accounts for 75% of global module production [18]. We estimate that the cost of producing PV modules in the U.S., assuming that all components are manufactured and assembled domestically, is \$0.38/W_{dc} (including a labor cost of \$0.12/W_{dc} assuming U.S. median wages for the manufacturing sector of \$27.70 per hour) [19,20]. We additionally estimate that the average 2021 cost of PV modules procured in the U.S., encompassing both domestically-produced and imported products, is \$0.31/W_{dc} (including 10% shipping cost), reflecting that a large share of solar PV (49%) are imported from China, Singapore, Taiwan, and Vietnam [20–22]. The cost of solar components has been changing in recent years, including temporary increases in polysilicon [23] and shipping costs [24] as well as decreases in costs resulting from efficiencies in wafer processing, cell assembly, and module assembly [23].

For land-based wind turbines, we estimate a 2021 global average cost of \$0.92/W (including a labor cost of \$0.27/W), which is estimated based on the market share and reported prices of major wind turbine manufacturers including GE (\$0.96/W, 47%), Vestas (\$0.96/W, 26%), Siemens-Games Renewable Energy (\$0.77/W, 13%), and Nordex (\$0.85/W, 13%) [25]. For offshore wind turbines, we estimate a global average cost of \$1.30/W (including a labor cost of \$0.38/W) [26]. There are no publicly-available data to estimate the domestic and global cost spreads for land-based wind turbine components, and correspondence with wind turbine manufacturers indicated that there is little notable cost difference after accounting for shipping. This assumption aligns with the substantial U.S. manufacturing share in the onshore wind sector [25], which indicates domestic wind turbine component manufacturing was broadly competitive with imports prior to IRA. Given the nascent state of the U.S. offshore wind industry, there are no publicly-available data on U.S. manufacturing costs, but costs of globally and domestically-produced offshore wind components are likely to be approximately comparable [26].

We also estimate costs associated with renewable energy project development and installation, including balance of system, labor, equipment, permits, and contingency costs. Including the baseline components mentioned earlier (i.e., PV modules and wind turbines), the baseline 2021 installed capital costs for different types of projects are as follows: \$1.17/W_{ac} for utility-scale solar, \$1.36/W for land-based wind, \$3.87/W for offshore fixed-bottom wind, and \$5.58/W for offshore floating wind (see SI Table S8-S10). We estimate operating and maintenance (O&M) costs for utility-scale solar, land-based wind, offshore fixed wind, and offshore floating wind are \$0.02/W/year, \$0.04/W/year, \$0.11/W/year, and \$0.12/W/year, respectively [21,26] (see SI Table S11). We assume U.S. median wages for the construction sector of \$29.33 per hour [19].

In addition, we model U.S. average grid interconnection costs, including permitting, inspection, and interconnection fees ($0.02/W) as well as line costs ($0.01/W) for utility-scale solar assuming an average spur line distance of 1.7 miles for a 100 MW system [21]. The associated interconnection costs for land-based wind are $0.136/W, while offshore fixed and floating wind entail costs of $0.69/W and $0.75/W, respectively [27]. When considering the spatial distribution of levelized cost of energy and deployment of wind and solar in Sections 4 and 5, we assess spatially-explicit grid connection costs following the methodology outlined by Patankar et al. (2023) [28], which considers factors such as proximity to the nearest substation, the capacity and voltage level of the transmission line, least-cost routing of lines, and the construction expenses associated with the line. An illustration of the spatially-explicit interconnection costs for utility-scale solar (4x4 km resolution) and land-based wind (8x8 km resolution) is provided in SI Figure S4.

To account for changes in capital and O&M costs over time associated with inflation, technological advancements, and economies of scale, we apply temporal scaling factors derived from the 2022 NREL Annual Technology Baseline (ATB) [29] (see SI Figure S2). Figure 1a illustrates the projected average capital costs and lifetime O&M costs for the U.S. from 2021 to 2050.

2.2 Domestic content shares

In 2021, the U.S. domestic content share for PV modules is 15.6%, whereas domestic production of polysilicon, wafer, cell, and inverters is negligible [22]. While the domestic production of PV modules has increased in recent years, there has been a decline in the domestic production of inverters despite increased deployment [20]. Domestic content shares for land-based wind products ranges from 15% to 25% for blades, 85% to 100% for nacelles, and 55% to 70% for towers [25]. Given that offshore wind development in the U.S. is nascent, there is negligible domestic manufacturing. In general, domestic content shares for PV and land-based wind are uncertain and highly variable over time as result of supply chain constraints, price variation, public policy (including tariffs and the IRA), and changes in annual market deployment.

2.3 Capacity factors

To determine average levelized costs of electricity for wind and solar projects, we use the U.S. average capacity factors reported in the 2022 NREL ATB[17], which are 24.4% for utility-scale solar, 43.1% for land-based wind, 49.0% for offshore fixed wind, and 38.1% for floating offshore wind (refer to SI Table S12). To account for technological advancement, we increase baseline capacity factors over time based on the NREL ATB (refer SI Figures S2 and S3). Figure 1b depicts the projected U.S. average capacity factors from 2021 to 2035. Additionally, we use spatially-explicit capacity factors for utility-scale solar and land-based wind reflecting geographic variations in resource potential. We use gridded capacity factor estimates (4km x 4km for utility-scale solar and 8km x 8km for land-based wind) from Leslie et al. (2021) [30], which further accounts for areas that are unsuitable to develop based on geospatial screening of physical and environmental attributes. Figures 1c and 1d depict spatially-explicit baseline capacity factors for 2021.

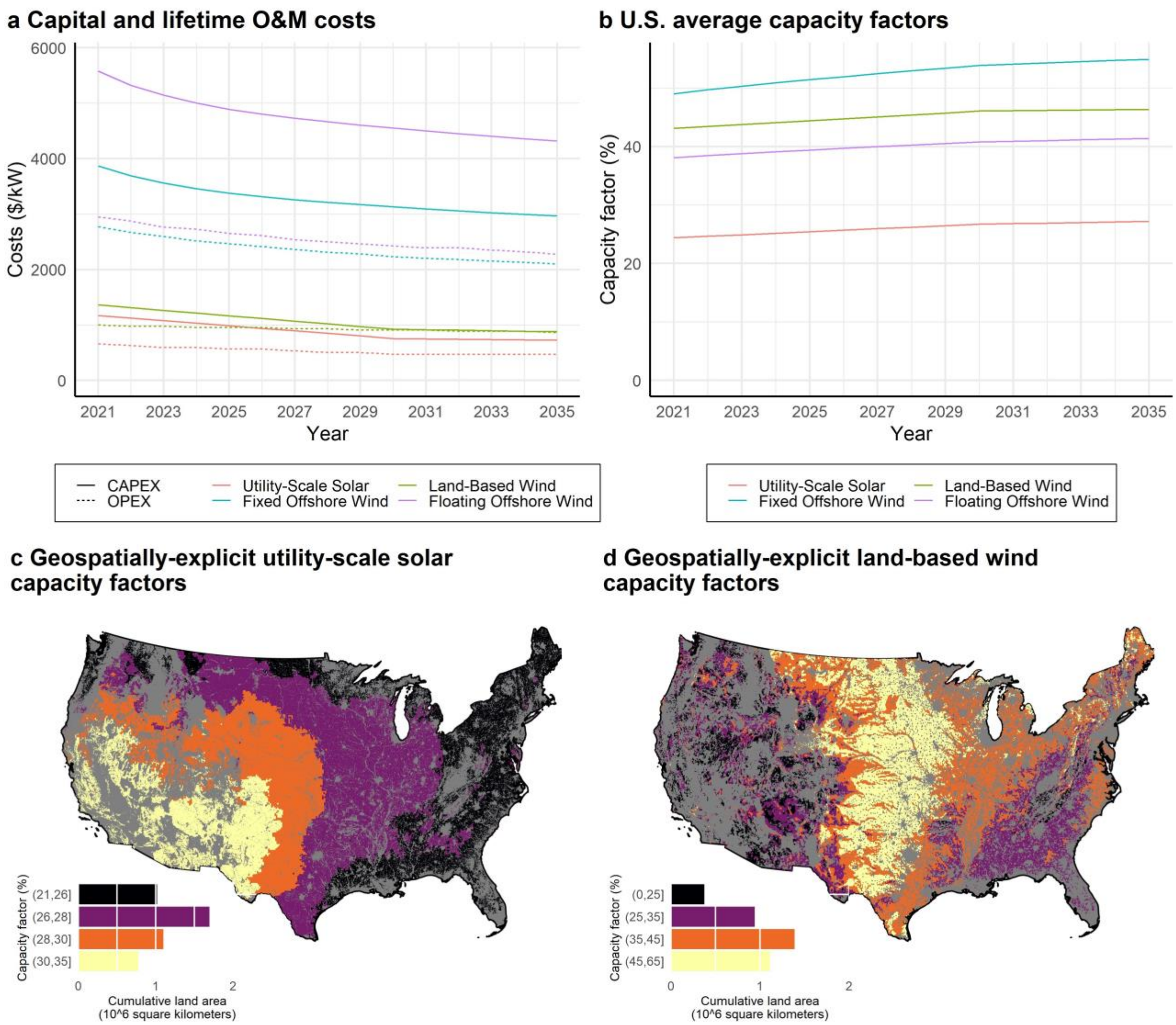

Figure 1. Estimated average capital costs, lifetime O&M costs, and capacity factors for each technology. U.S. average (a) capital costs (excluding interconnection costs) and lifetime O&M costs and (b) capacity factors from 2021 to 2050. Spatially-explicit capacity factors in 2021 for (c) utility-scale solar (4x4 km resolution) (d) land-based wind (8x8 km resolution). In (c) and (d), gray shaded regions indicate exclusion areas deemed unsuitable for development.

2.4 Levelized cost of electricity simulation

The following provides an overview of the approach used to estimate the levelized cost of electricity (LCOE), which is a measure of the cost of electricity generation for a project over its lifetime. LCOE can also be thought of as the minimum average revenue a project must earn per unit of electricity sold over its lifetime to recover all costs, including debt, and a minimum targeted rate of return on equity. In the context of this study, the LCOE is useful for investment planning from the perspective of a renewable developer, for comparing the cost of a specific electricity generation source across locations, and for estimating the combined impact of policy incentives on a consistent basis. We use the following simple LCOE formulation, which is a modification of that used in NREL (2021) [27]:

$$\boldsymbol{LCOE} = \frac{[(\boldsymbol{CC}-\boldsymbol{AMPC})\times(\boldsymbol{1}-\boldsymbol{ITC})]\times\boldsymbol{FCR}+\boldsymbol{OC}+\boldsymbol{IC}}{\boldsymbol{8760}\times\boldsymbol{CF}} - \boldsymbol{PTC} \quad (1)$$

where CC is the capital cost (\$/ W), FCR is the fixed charge rate (%), OC is the annual O&M cost (\$/W/yr), IC is the annualized cost of grid interconnection (\$/W), and CF is the capacity factor (%). We additionally include implications of policy provisions, including the ITC (%), PTC ($\$/Wh$), and $AMPC$ (\$/W).

Details regarding the parameterization, formulation, and sample calculations for the tax credits accounting for *energy community* and *domestic content share* tax credit adders, sunsetting provisions, and financing adjustments are provided in SI Section 1.2 and 1.3. All monetary estimates are in units of 2022 real U.S. dollars (2022\$), unless otherwise noted.

Besides the costs and capacity factors, there are various other financial parameters used in estimating the LCOE. Specifically, the fixed charge rates (FCR), which reflect the annualized payments required to repay debt and equity financing for a project, are assumed to be 5.13% for utility-scale solar, 5.88% for land-based wind, and 5.82% for offshore wind [27,29]. Given that the PTC is available for 10 years, while wind and solar asset life are assumed to be 25 and 30 years, respectively, we also convert the PTC to an equivalent net present value over the total asset life using technology-specific real weighted-average costs of capital (WACC) as the discount rate (i.e., 2.70% for utility-scale solar, 2.72% for land-based wind, 2.80% for offshore wind) [27,29]; refer to SI Table S15. We also assume a credit transfer overhead of 7.5% to reflect administrative costs or transaction fees associated with transferring or monetizing available tax credits [31], under the assumption that most project developers will not have a sufficient tax basis to make use of direct tax credits and hence are dependent on transferability of credits. Note that we likewise do not consider the impact of modified accelerated depreciation (MACRS) on after-tax LCOE, as depreciation allowances are non-transferable.

With respect to transmission interconnection costs, we adopt a WACC of 4.4% and a capital recovery period of 60 years [28,32]. The implicit assumption is that all transmission project costs are directly associated with renewable energy projects, thus overlooking other rationales for expanding transmission capacity, such as enhancing grid reliability and mitigating congestion.

In addition, we perform a sensitivity analysis to account for the impact of high inflation and interest rates on financing costs. Steffen et al. compared historical nominal WACC values reported for 46 countries over the period 2009 to 2017 [33]; we use the highest empirical nominal WACC values for OECD countries reported in Steffen et al., adjusted for the highest annual U.S. inflation rate observed from 2012 to 2022 (8%, 2022) based on Consumer Price Index (CPI) data from the U.S. Bureau of Labor Statistics [34]. For the high inflation sensitivity, we assume real WACC (FCR) are 5.37% (7.46%) for utility-scale solar and 5.09% (7.87%) for land-based and offshore wind.

2.5 Renewable deployment simulation

We simulate the spatial deployment of land-based wind and utility-scale solar projects induced by the IRA from 2024 to 2035. We assume capacity additions across 25 regions in the contiguous U.S. in 2- to 3-year increments (2023-2024, 2025-2026, 2027-2028, 2029-2030, 2031-2032, 2033-2035) reported by the Rapid Energy Policy Evaluation and Analysis Toolkit (REPEAT) Project [8,35]; the REPEAT project used RIO [36], a macro-energy system optimization model, to select cost-optimal technological pathways for the U.S. energy system, given the implementation of the IRA. We spatially downscale capacity additions from the regional scale to higher resolution grid locations (4x4 km for utility-scale solar, 8x8 km for land-based wind). For each aggregate cluster of projects selected for deployment in RIO, we assume that candidate renewable energy sites within the aggregate cluster will be cost-optimally selected based on time-variant, spatially-explicit LCOEs in each time increment, accounting for transmission interconnection costs at each grid location. We further identify whether deployment locations are in census tracts identified as disadvantaged communities based on the Climate and Economic Justice Screening Tool from the White House U.S. Council on Environmental Quality [9]. This renewable deployment simulation is used to assess the spatial distribution of infrastructure, the implications of place-based policies (i.e., *energy community* tax credit), and the flow of investments to disadvantaged communities.

2.6 Policies scenarios

We model technology costs for the following five policy scenarios: 1) no tax credits (baseline), 2) *base* rate PTC or ITC tax credit (labeled PTC/ITC), 3) *bonus* rate PTC or ITC tax credit (+PTC/+ITC), 4) *bonus* rate PTC or ITC tax credit and the adder for meeting either the *domestic content* or *energy community* requirement (+PTC1/+ITC1), or 5) *bonus* rate PTC or ITC tax credit and the adder for meeting both the *domestic content* and *energy community* requirements (+PTC2/+ITC2).

We additionally do a sensitivity analysis, alternatively assuming that the value of 45X manufacturing tax credits for domestic manufactured content are *not transferred* or *fully transferred* through to installed renewable project cost; the degree to which lower manufacturing costs pass through to prices for solar or wind components or installed projects is uncertain and depends on competitive market dynamics. Domestic manufacturers may retain some portion of the 45X tax credit value. Given that incentives of the IRA are designed to induce increased domestic manufacturing, we perform another sensitivity analysis, alternatively assuming current (as of 2021) domestic content shares and 100% domestic shares. We do not account for all provisions within the IRA that can indirectly impact renewable costs (e.g., section 48C advanced energy project credit, loan guarantee programs).

3 Impacts of the IRA on solar and wind component costs

Figure 2 depicts the production cost spread between globally- and domestically-produced solar and wind components and the implications of the 45X manufacturing tax credit. Absent the 45X tax credit, as shown in Figure 2a, globally-produced components have a comparative cost advantage over domestically-produced components across the solar supply chain. For example, the global average cost for PV modules (excluding tariffs) was approximately 28% lower than U.S.-produced modules composed of 100% domestically-manufactured components in 2021. This domestic production cost premium (in part) accounts for the low domestic manufacturing shares observed in the U.S. solar PV sector in 2021 [22]. The manufacturing incentives established by the IRA reverse this relative cost advantage: after accounting for the impact of the 45X tax credit, U.S.-produced solar PV components across the full supply chain (including polysilicon ingots, wafers, cells, and module assembly as well as inverters) are likely to have a comparative cost advantage relative to globally-produced components. We estimate that, due to 45X, the cost of PV modules using 100% U.S.-manufactured components is approximately 10% lower than imported modules (before accounting for tariffs). Looking across the PV supply chain, 45X results in a substantial cost advantage for U.S. manufacturing of silicon wafers (78% cheaper than imports) and solar PV cells (67% before accounting for tariffs), while U.S. production of polysilicon has only a narrow cost advantage which may be expanded or negated by local variations in energy input, labor, or construction costs. U.S. module assembly is 10% cheaper than imports after accounting for 45X (and before tariffs) while inverter manufacturing becomes 28% cheaper.

Since 2012, the United States has imposed various anti-dumping and countervailing duty (AD/CVD) tariffs on solar panels and cells imported from China. In 2015, these tariffs were revised and extended to impose a tariff on solar cells manufactured in Taiwan [37], and beginning in June 2024, AD/CVD tariffs will also be extended to products from Vietnam, Malaysia, Thailand, and Cambodia; these four countries currently account for the majority of solar module imports into the U.S. [38]. In 2018, President Trump imposed an additional 25% tariff on numerous Chinese products, including solar cells and modules, following an investigation under Section 301 of the Trade Act of 1974 regarding China's laws, policies, practices and actions related to intellectual property, innovation and technology. Finally, President Trump imposed Section 201 'safeguard' tariffs of 14.75% on solar cell and module imports regardless of country of origin, and these were extended by President Biden until February 6, 2026, after which tariffs step down by 0.25 percentage points each year [39]. As shown in Figure 2a, the costs of US-manufactured PV cells and modules with the 45X tax credit are 75% and 22% less expensive, respectively, than imported products after accounting for the global safeguard tariffs, while imports from China and/or from companies subject to AD/CVD tariffs are further disadvantaged relative to US producers.

Absent the 45X tax credit, we assume that costs for domestically- and globally-produced wind turbine components are approximately comparable, after accounting for transportation costs and logistics (see Section 2.1). Therefore, as shown in Figures 2b-c, the 45X tax credits will likely make U.S.-produced wind components less expensive than imports, further inducing the expansion of domestic wind manufacturing capacity. Specifically, the costs of land-based wind turbine blades, nacelles, and towers are 7%, 11%, and 16% lower than global costs, respectively, and the costs of domestically-produced offshore wind rotor-nacelle assembly and towers are 6% and 16% lower than global costs, respectively.

We do not account for the 48C investment tax credit for clean energy manufacturing facilities, which may further drive down the price of domestically-produced components at certain facilities. However, total outlays for 48C are capped at $10 billion under current statute, and the credit can be claimed for a wide range of clean energy manufacturing activities as well as investments to improve efficiency of existing manufacturing facilities. We therefore assume any impact of 48C on wind or solar manufacturing is likely to be inframarginal. Also, we report *production costs*, which can differ from final component *prices* resulting from competitive market dynamics (e.g., relative product pricing, producer margins, and pass-through of lower costs to purchasers).

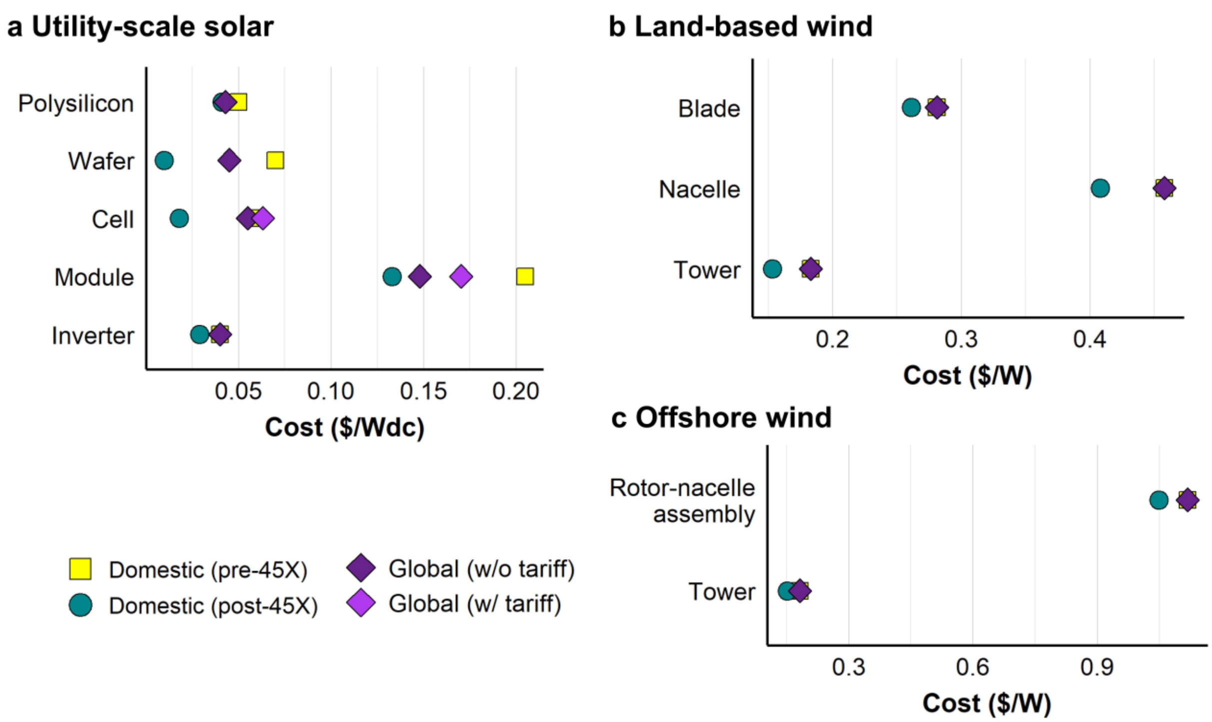

Figure 2. Costs in 2021 for utility-scale solar (a), land-based wind (b), and offshore wind (c) components. Costs are shown for domestically-produced components with and without the 45X tax credits, in addition to globally-produced components with and without the Section 201 'safeguard' tariffs on solar cells and modules (at a rate of approximately15%). Imports from China and certain companies subject to anti-dumping and countervailing duty provisions are subject to larger tariffs. Note that marginal costs for some solar components are provided; this includes costs for wafers (excluding polysilicon), cells (excluding wafers), and modules (excluding cells). Production costs may differ from final product pricing. Refer to SI Table S17 for additional details.

4 Impacts of IRA incentives on levelized cost of electricity from wind and solar

We explore the relative benefits and stackability (combined impact) of incentives for renewable developers, including the *base* and *bonus* rate ITC and PTC as well as the *domestic content* and *energy community* tax credit adders. Figure 3 depicts U.S. average levelized cost of electricity (LCOE) for each policy scenario and technology in 2030. For each technology, we present results for either the ITC or PTC tax credit, depending on which incentive has the comparative cost advantage; based on U.S. average capacity factors, the PTC is preferable for utility-scale solar and land-based wind, and the ITC is preferable for offshore wind.

We find that projects receiving the *base* rate PTC and ITC see a 9% reduction for utility-scale solar, a 13% reduction for land-based wind, and a 3% reduction for offshore wind. Projects receiving the larger *bonus* credit rate exhibit substantially lower cost, with the average LCOE of utility-scale solar and land-based wind projects receiving the *bonus* rate approximately 43% and 50% lower, respectively, than comparable projects receiving the *base* tax rate. Similarly, the LCOE of offshore wind projects receiving the *bonus* tax rate is approximately 13-14% lower than comparable projects receiving the *base* tax rate. Demonstrating compliance with the labor requirements to qualify for the *bonus* tax rate may add legal and compliance costs for project developers that are not estimated in this study. Additionally, we assume median wages to estimate the LCOEs, and do not model increases in project costs to meet prevailing wage requirements. While meeting prevailing wage requirements may lead to small increases in LCOE for projects that currently do no pay prevailing wages, we found in prior work that a 20% increase in installation and construction labor costs would increase the installed cost of solar and wind projects by only 3% and 1%, respectively [40]. Thus, we expect any additional project costs associated with meeting labor requirements to qualify for the *bonus* tax rate to be more than compensated by the increase in the tax credit. Projects qualifying for the *bonus* rate will thus exhibit a significant cost advantage over comparable projects receiving the *base* credit value, making it likely that markets will be dominated by developers complying with the *bonus* credit requirements for prevailing wage and apprenticeships.

In addition, we assess the implications of the *energy community* and *domestic content* adders. The LCOE for projects receiving either adder is 6-10% lower than comparable projects receiving just the *bonus* rate ITC or PTC, and projects receiving both adders may be 12-20% cheaper.

We perform sensitivities to account for uncertainty in component costs associated with the 45X manufacturing tax credit and changing domestic content shares. Specifically, there is uncertainty regarding the extent to which production cost reductions associated with the 45X manufacturing credit will be passed through from the manufacturer to the purchaser. To bound the effect, we alternatively assume that there is no pass-through and full pass-through of cost reductions to the developer. We find that full pass-through decreases costs to the developer by 10-20% for utility-scale solar and 3-13% for land-based wind as illustrated in the scenarios depicted in Figure 3.

Furthermore, given substantial estimated cost advantages for both domestic manufacturers due to 45X and for wind and solar project developers qualifying for the *domestic content* adder to the PTC/ITC, the collection of provisions in the IRA is likely to induce significant demand for solar and wind components manufactured in the U.S. However, the extent that domestic manufacturing capacity will expand is uncertain. To assess the range of impact, we alternatively assume current and 100% domestic content shares of renewable products. We find that prior to considering 45X, increasing the domestic content share from current rates to 100% would increase the LCOE for utility-scale solar by 5-20%. However, even a partial pass-through of the 45X manufacturing credit to developers has the potential to offset increases in component costs associated with increasing domestic content shares. If domestic producers price their products competitively against imports, solar project costs using domestic content would see no cost increase, while more complete pass-through of domestic cost advantages created by 45X would *lower* solar LCOEs.

We also perform a sensitivity analysis to account for uncertainty in key project financing assumptions that may substantially impact investment decisions [33]. Specifically, we find that high inflation rates (similar to 2022) combined with higher interest rates have the potential to substantially increase the LCOE for utility-scale solar (33-50%) and land-based wind (20-33%). However, solar and wind projects receiving the *bonus* PTC value remain considerably cheaper than pre-IRA estimated costs even in this high interest rate environment.

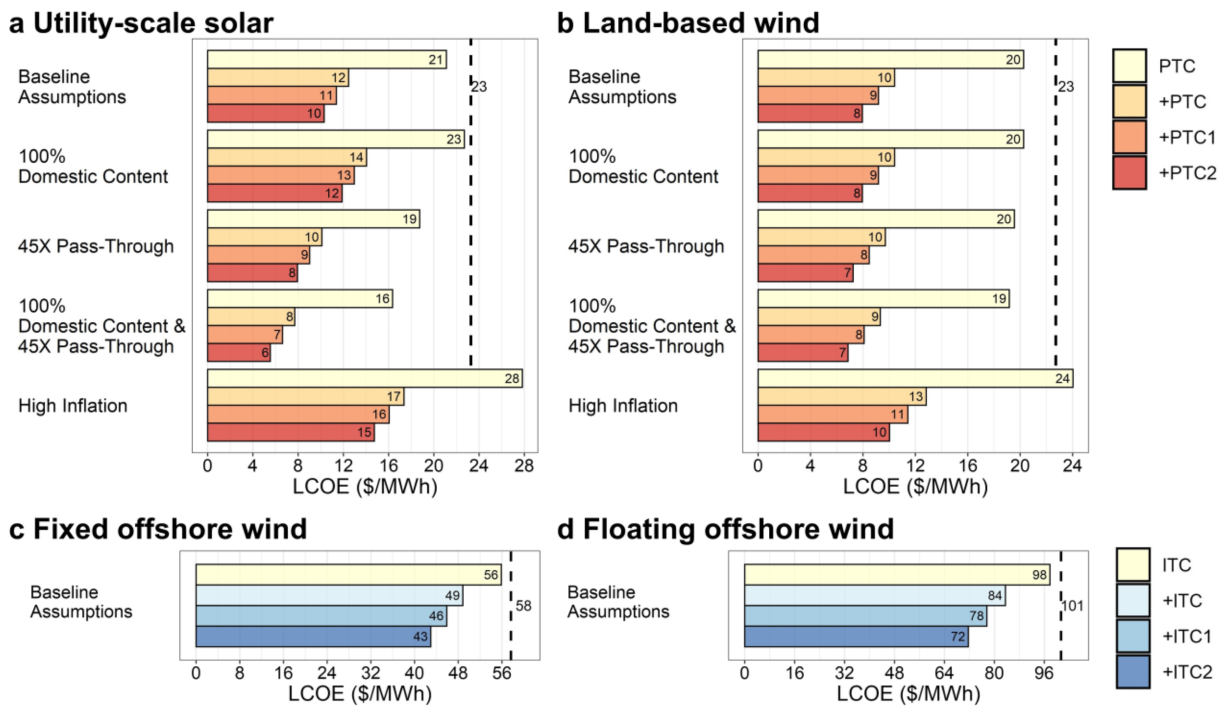

Figure 3. U.S. average LCOE in 2030 for utility-scale solar (in 2022$) (a), land-based wind (b), fixed offshore wind (c), and floating offshore wind (d). Bars represent LCOEs for alternative policy scenarios, and dotted lines represent LCOEs absent the IRA. Baseline assumptions include current domestic content shares of components (as of 2021), no pass-through of the 45X manufacturing tax credit, and average inflation rates. A sensitivity analysis is performed in which key assumptions are varied; assumptions that differ from the baseline assumptions are indicated in the figure.

Figure 4 illustrates the impact of solar and wind capacity factors on LCOE. We find that the preferred incentive (i.e., ITC versus PTC) may depend on the capacity factor for each technology, as higher capacity factor leads to greater value from the PTC. The PTC generally is more cost-effective than the ITC for utility-scale solar and land-based wind technologies, regardless of the capacity factor. IRA extends PTC eligibility to solar PV for the first time, and this result indicates that most utility-scale solar projects are likely to elect the PTC over the ITC going forward. For floating offshore wind, the ITC is always more cost-effective than the PTC, regardless of capacity factor, given current cost estimates for these projects. For fixed offshore wind, the differential in LCOE with the ITC and PTC incentives are very similar, and the most cost-effective incentive varies based on capacity factor.

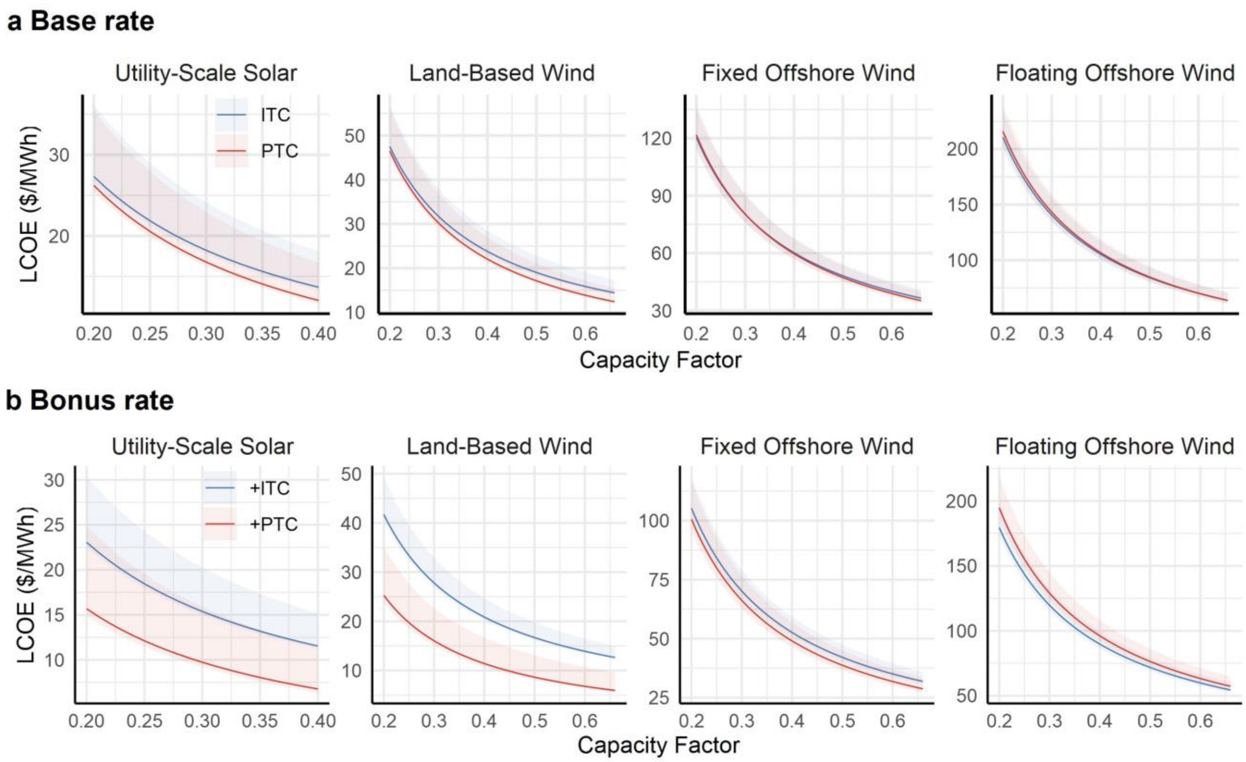

Figure 4. LCOEs as a function of capacity factor for each technology (in 2022$). The impact of capacity factors is evaluated for the *base* (a) and *bonus* (b) tax credit rates. The LCOE for 2030 is depicted by solid lines, while the shaded regions represent the potential range of LCOE values from 2023 to 2035. These cost estimates assume current domestic content shares for renewable products (as of 2021) and do not include pass-through of the 45X manufacturing tax credit.

Figure 5 depicts the LCOE projections for projects that begin construction between 2022 and 2032 assuming average capacity factors (see SI Figure S6 for LCOE projections out to 2050). These LCOE projections reflect declining renewable technology costs and improvements in average capacity factors over time. Note that IRA specifies that incentives for the ITC and PTC will phase down over a four-year period (at 100%, 75%, 50% and 0% of full value) beginning the year after 2032 *or* the year after the power sector reduces greenhouse gas emissions to 25% of 2022 levels, whichever comes later.

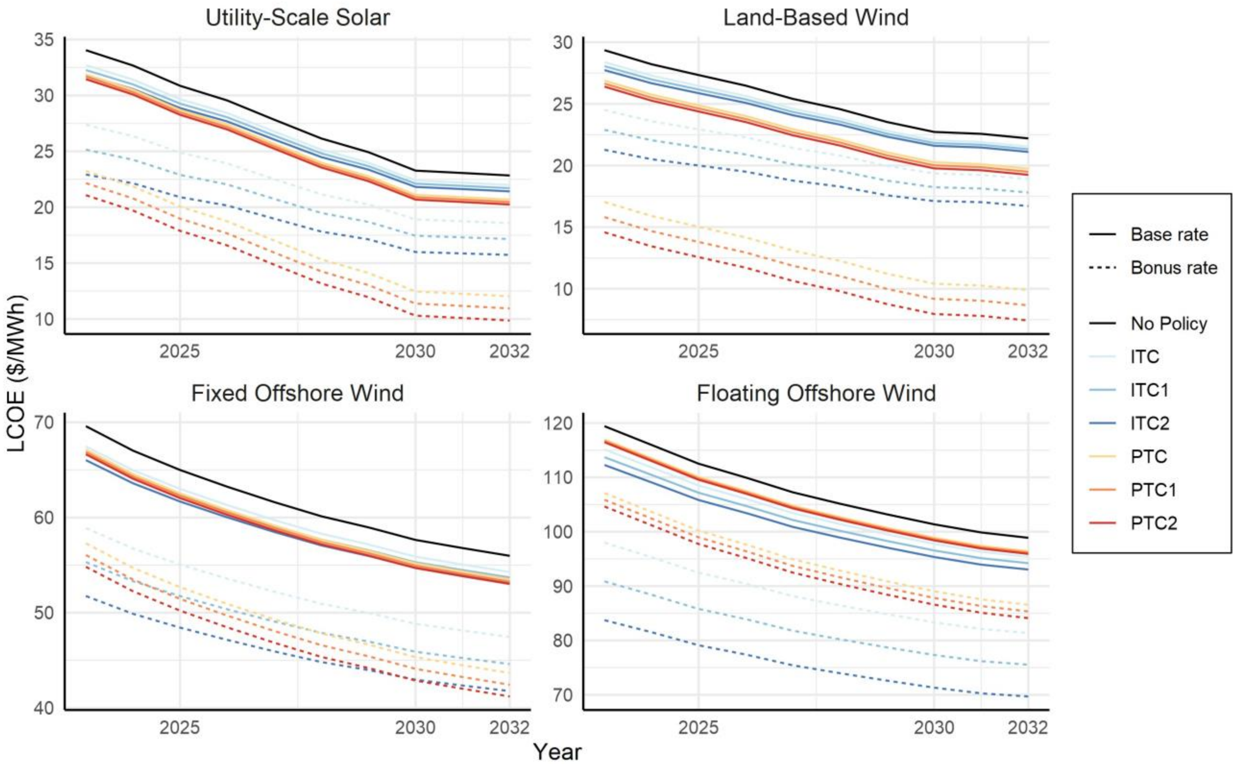

Figure 5. LCOEs for alternative policy scenarios from 2022 to 2032 (in 2022$). These cost estimates assume current domestic content shares for renewable products (as of 2021) and do not include pass-through of the 45X manufacturing tax credit.

Figure 6 depicts spatially-explicit LCOE estimates for alternative policy scenarios in 2030. The greatest cost reductions associated with policy incentives (in absolute terms relative to the no policy scenario) are in South Texas and the Southeast for utility-scale solar and the West and Southeast for land-based wind (refer to SI Figure S9).

Spatial variation in LCOE estimates reflect heterogeneous wind and solar resource potential, transmission interconnection costs, and qualification for the *energy community* tax credit adder. To demonstrate the influence of transmission interconnection on renewable costs, we model both spatially-explicit transmission interconnection costs that account for routing to existing lines and load centers (as shown in Figure 6) and generic transmission costs that are not spatially explicit (as shown in SI Figure S7). We find that the inclusion of more realistic spatially-explicit interconnection costs increases our estimate of average LCOE by 47% (no policy) to 90% (+PTC1 scenario) for utility-scale solar, and 24% (no policy) and 83% (+PTC1 scenario) for land-based wind.

Figure 7 is a transposition of the spatially-explicit LCOEs into supply curves for candidate project areas across the continental United States. The tax incentives established by the IRA make many regions economically viable to develop that historically have not been (notwithstanding transmission siting and other constraints). Assuming projects qualify for the *bonus* rate PTC, we estimate that roughly 20 TW of potential solar PV sites and 2.5 TW of land-based wind sites are available with a 2030 levelized cost of $20/MWh or less (though not all of these sites are likely to be simultaneously developed due to local siting constraints and cumulative impact). In general, application of the tax credits represents a monotonic transformation of the spatially-explicit LCOEs (shown in Figure 7), such that costs across potential renewable sites decline but the relative ranking of or preference between sites is constant. The exception is sites that qualify for the *energy community* tax credit adder may become relatively more attractive than sites that do not qualify.

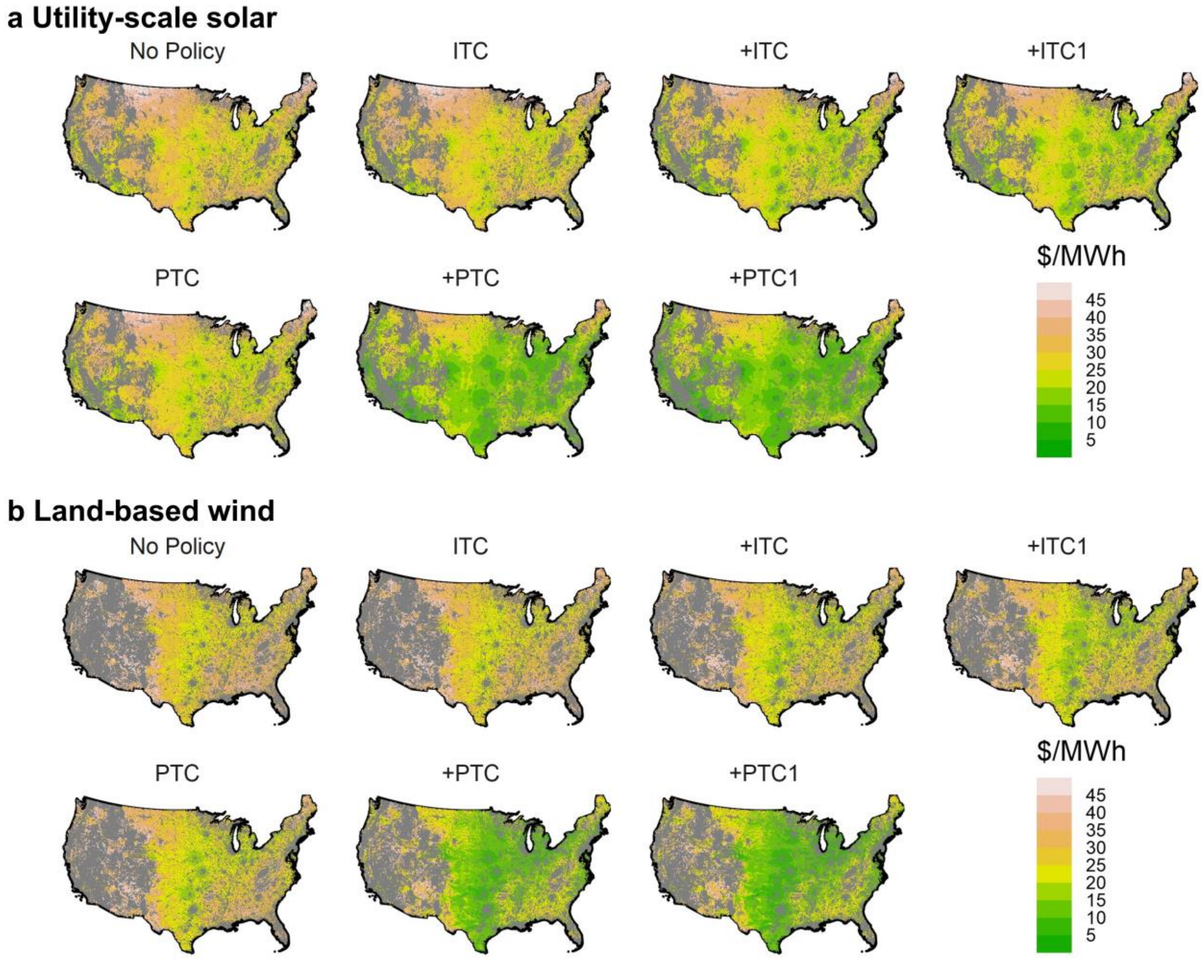

Figure 6. Spatially-explicit LCOE for utility-scale solar (a) and land-based wind (b) for alternative policy scenarios in 2030 (in 2022$). Gray shaded regions indicate areas that are unsuitable for project development based on a site suitability screening [30] or with an LCOE over $50/MWh. These cost estimates include spatially-explicit interconnection costs, assume current domestic content shares for renewable products (as of 2021), and do not include pass-through of the 45X manufacturing tax credit.

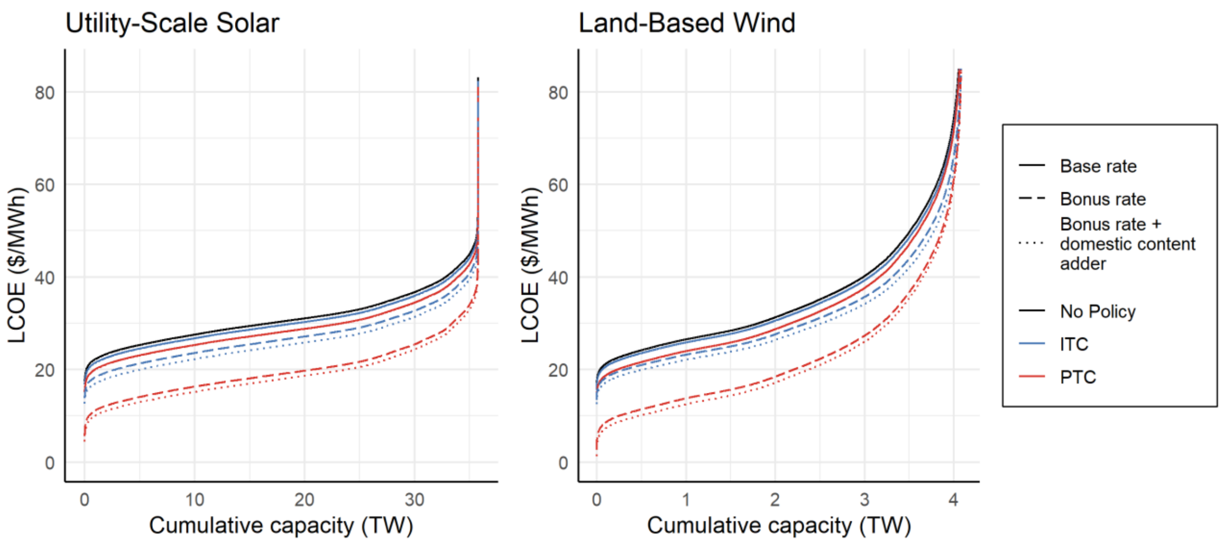

Figure 7. Utility-scale solar and land-based wind supply curves for alternative policy scenarios in 2030 (in 2022$). These cost estimates assume current domestic content shares for renewable products (as of 2021) and do not include pass-through of the 45X manufacturing tax credit. These supply curves are a transposition of the maps in Figure 6.

5 Deployment of renewable energy capacity induced by the IRA

Figure 8 depicts the simulated deployment of land-based wind and utility-scale solar projects induced by the IRA from 2024 to 2035. Based on REPEAT Project analysis of the impacts of the Inflation Reduction Act published in July 2023 [41], we assume that 740 GW of utility-scale solar and 450 GW of land-based wind are deployed by 2035; this represents a 1.7-fold and 2.5-fold increase in utility-scale solar and land-based wind deployment, respectively, relative to a scenario without the IRA. The geographic distribution of cost optimally-deployed renewable projects is intended to be illustrative, given uncertainty in spatially-explicit development costs as well as non-cost drivers of renewable siting decisions (e.g., public opposition, permitting constraints) [42,43].

Renewable resource potential, in addition to transmission costs and proximity have a substantial influence on renewable siting decisions. The base and bonus rate ITC and PTC incentives create a cost advantage for wind and solar power relative to other technologies, thus inducing large-scale renewable energy deployment across the U.S. In general, the tax credits monotonically transform the spatially-explicit LCOEs, and thus, the most preferred or least-cost sites are generally the same with or without the IRA. The exception is that sites that qualify for the *energy community* tax credit adder become relatively more attractive than other sites that have marginally higher capacity factors but do not qualify for the tax credit adder. However, reductions in development costs associated with the *energy community* tax credit are relatively small and do not substantially change siting patterns when transmission costs are considered.

Place-based policies are often intended to incentivize targeted investment in overburdened, underserved, or disadvantaged communities [44]. Absent the energy community tax credit, nearly a third of utility-scale solar (27%) and half of wind (46%) capacity are sited in disadvantaged communities, defined based on environmental, climate, socioeconomic, and other burdens by the White House Council on Environmental Quality. We also find that the energy community tax credit marginally spurs utility-scale investment in disadvantaged communities, given that there is some intersection between the definitions of an *energy community* and *disadvantaged community*. Notably the goal of the Justice40 Initiative is that 40% of benefits (e.g., local tax revenues, jobs) of federal investment flow to disadvantaged communities. However, even if a large share of renewable *capacity* and *investment* flow to disadvantaged communities, this does not necessarily mean that *benefits* will similarly flow to disadvantaged communities.

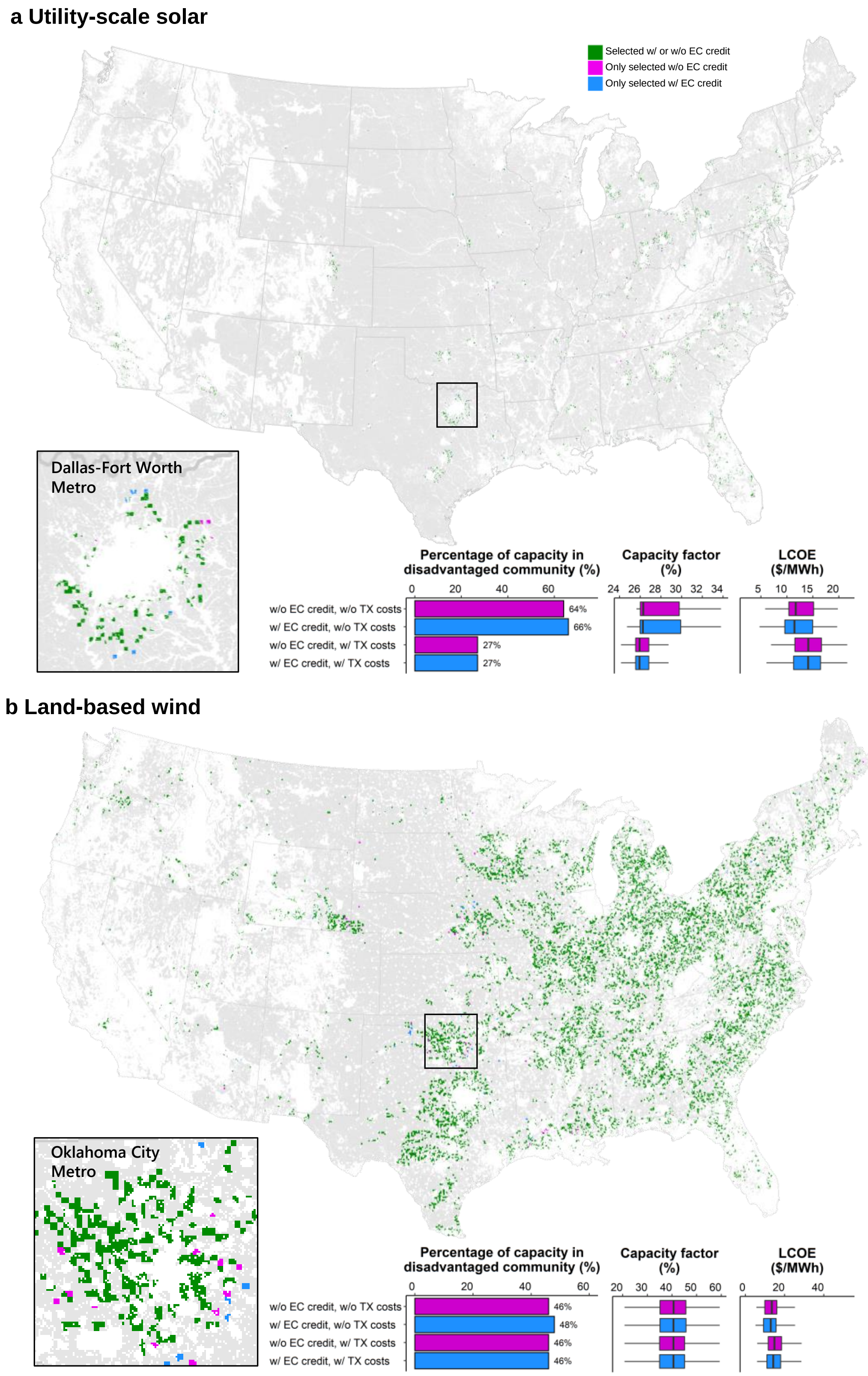
a Utility-scale solar
Selected w/ or w/o EC credit
Only selected w/o EC credit
Only selected w/ EC credit
Dallas-Fort Worth Metro
Percentage of capacity in disadvantaged community (%)
0 20 40 60
Capacity factor (%)
24 26 28 30 32 34
LCOE ($/MWh)
5 10 15 20
w/o EC credit, w/o TX costs
w/ EC credit, w/o TX costs
w/o EC credit, w/ TX costs
w/ EC credit, w/ TX costs
64%
66%
27%
27%
b Land-based wind
Oklahoma City Metro
Percentage of capacity in disadvantaged community (%)
0 20 40 60
Capacity factor (%)
20 30 40 50 60
LCOE ($/MWh)
0 20 40
w/o EC credit, w/o TX costs
w/ EC credit, w/o TX costs
w/o EC credit, w/ TX costs
w/ EC credit, w/ TX costs
46%
48%
46%
46%

Figure 8. Spatial distribution of utility-scale solar (a) and land-based wind (b) capacity deployed between from 2024 to 2035. We assume that projects are cost-optimally deployed and qualify for the bonus rate PTC. The maps depict alternative siting patterns with and without the energy community (EC) tax credit and accounting for the transmission (TX) interconnection costs; SI Figure S9 depicts siting patterns without TX interconnection costs. Under alternative assumptions regarding the EC tax credit and TX interconnection costs, we also show the distribution of capacity factors and LCOEs across selected grid cells as well as identify the percentage of capacity that is sited in disadvantaged communities.

6 Policy implications

The IRA contains various provisions intended to address both cost and non-cost barriers across renewable supply chains. There are incentives for manufacturers, such as the 45X manufacturing credit, to spur onshoring of U.S. manufacturing capacity, drive down domestic production costs to be globally competitive, and moderate supply chain risks. There are also incentives for project developers, namely the investment and production tax credits (ITC and PTC), to incentivize large-scale investment and deployment of renewable generation capacity. The labor requirements associated with the *bonus* rate ITC and PTC have the potential to further benefit developers as well as workers by easing labor supply constraints (that are already present in renewable industries) and by better attracting and retaining the workforce through higher compensation and expanded apprenticeship opportunities. The intention of the *domestic content* adder is to induce demand for domestically-produced materials and products, which has the potential to further spur onshoring of wind and solar manufacturing. In addition, the *energy community* adder has the potential to moderate economic losses associated with declining fossil fuels as well as direct investment in areas that have historically been underserved and overburdened.

Overall, this study suggests that the collection of policies within the IRA has the potential to meet these intended climate and economic goals. However, there is often (if not always) a gap between intended and actual policy outcomes. Many of the provisions in the IRA are untested and unprecedented in design and scale, and there is uncertainty with respect to how these policies will interact and manifest in a dynamic market and political conditions. While the IRA provisions help reduce many cost and non-cost barriers to renewable deployment, there are also limitations that can (in part) be mitigated through complementary federal and state public policies and programs. For example, much of the societal benefits from the IRA may be eroded absent reforms to federal transmission permitting, planning, and cost allocation and additional incentives [45] and programmatic support to moderate labor supply constraints [15].

Declaration of competing interest

JJ is part owner of DeSolve, LLC, which provides techno-economic analysis and decision support for clean energy technology ventures and investors. He serves on the advisory boards of Eavor Technologies Inc., a closed-loop geothermal technology company, and Rondo Energy, a provider of high-temperature thermal energy storage and industrial decarbonization solutions and has an equity interest in both companies. He also serves as a technical advisor to MUUS Climate Partners and Energy Impact Partners, both investors in early-stage climate technology companies.

The other authors declare no competing interests.

Author contributions

EM and JJ conceptualized the study and acquired funding. YM and MB performed the formal analysis under the supervision of EM and JJ. All authors analyzed the results as well as wrote and revised the manuscript.

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Data availability

Code and data supporting the analysis are provided in the following public repository: [link to be included].

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