Existing fossil fuel plants sharing grid access with renewables can rapidly and cost-effectively double US generation capacity

Working Paper

November 2024

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Abstract: *Timely grid access for the large volume of renewable energy (RE) projects awaiting in the queue has become a significant bottleneck for meeting growing electricity demand with low-cost clean energy. However, recent cost declines in renewables combined with incentives from the Inflation Reduction Act enable the siting of low-cost renewables near existing interconnection. Here, we utilize high-resolution satellite imagery to estimate the renewable energy (RE) potential within a 6x6 mile buffer zone around existing fossil power plants in the United States (US). We find that it is technically feasible and economically viable for existing fossil power plants to share their grid access with around 800 GW of renewable energy (RE) currently, and around 1,000 GW by 2030 as the economics of RE continue to improve, potentially nearly doubling the US generation capacity and significantly reducing the cost of electricity. We argue that a significant opportunity likely exists for large-scale RE and storage deployment by sharing grid access with about 250 GW of RE plants that currently utilize their grid connections less than 70% of the time, warranting further evaluation. By improving the utilization of existing infrastructure, this strategy bypasses traditional renewable integration challenges such as the interconnection queue backlog while also generating additional revenue for power plant owners and tax revenue for local communities. Despite limited commercial interest today, with appropriate policy and regulatory support, this can be a mainstream strategy for integrating clean electricity sources at speed and scale.*

Modeling results are available at: scarcitytosurplus.com/dashboard

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Introduction

The power system has emerged as the major bottleneck to meeting growing electricity demand with low-cost clean energy. Demand for electricity - and in particular, clean electricity - has soared, driven by the electrification of various sectors, the rise of data centers for artificial intelligence (AI), and booming investment into clean tech manufacturing. Simultaneously, clean energy is increasingly economically viable due to dramatic declines in the costs of renewables and battery storage coupled with incentives from the Inflation Reduction Act (IRA): for example, the prices of utility-scale solar Power Purchase Agreements (PPAs) reached a record-low of $24/MWh for projects beginning commercial operation in 2023 while nearly half of the new PPAs signed in 2023 qualify for the energy community tax credit and have achieved similar prices (1). Yet in the United States (US) today, nearly 1,500 GW of solar and wind plus over 1,000 GW of battery storage remain stalled in the interconnection queue, where projects seeking to connect to the grid wait while they undergo a series of system impact studies that analyze if, and which, network upgrades are needed before the project can be brought online (2). The active capacity in the queue has been growing, translating to increased interconnection wait times: while the typical duration from interconnection request to commercial operation averaged less than two years for projects built in 2000-2007, projects built in 2023 have a median wait of five years (2). Challenges associated with executing the transmission upgrades exacerbate the issue, with lead times for transformers recently surging to two to four years (3).

These grid bottlenecks are translating to a lagging rate of renewable energy (RE) deployment, which needs to be accelerated if projected load growth is to be delivered at the lowest cost. At the national level as shown in Figure 1, even in the optimistic case in which the current average rate of 30 GW/year is doubled (e.g. through streamlined interconnection processes), maintaining this pace until 2035 will likely fall short by ~1000 GW compared to the least-cost projections by several major studies. Some predictions indicate that AI data centers alone could require up to 500 TWh of electricity by 2030, absorbing almost all new RE additions assuming deployment continues at its current pace (4). In the absence of cleaner alternatives, this generation shortfall would have to be met by fossil generation, with corresponding emissions and costs. In contrast, other global players like China are deploying RE at rates ten times higher than the US, reaping the benefits of low-cost energy for their consumers and industries. While 2024 is projected to be a record-setting year with 45 GW of RE commencing commercial operation, additional efforts are required to fill the gap (5).

PJM's resource adequacy risk

The Pennsylvania-New Jersey-Maryland (PJM) Interconnection, the largest grid operator in the US by customers served, faces significant challenges in maintaining resource adequacy. Load forecasts show demand growth averaging 1.4% per year for the PJM footprint and up to 7% for zones with data centers clusters, signifying unprecedented growth in electricity demand. Yet simultaneously, 40 GW of fossil generation capacity (21% of PJM's currently installed capacity) may retire by 2030 and the rate of new capacity additions and in particular RE and battery storage has lagged (6). This asymmetrical pace in which resource retirements and load growth exceed the pace of new entry may translate into a potential capacity shortfall of nearly 4 GW by 2029, escalating to over 8 GW by 2034 if current trends hold. This underscores the urgent need for accelerating the integration of new resources and in particular RE and battery storage solutions to meet future demand and support grid reliability.

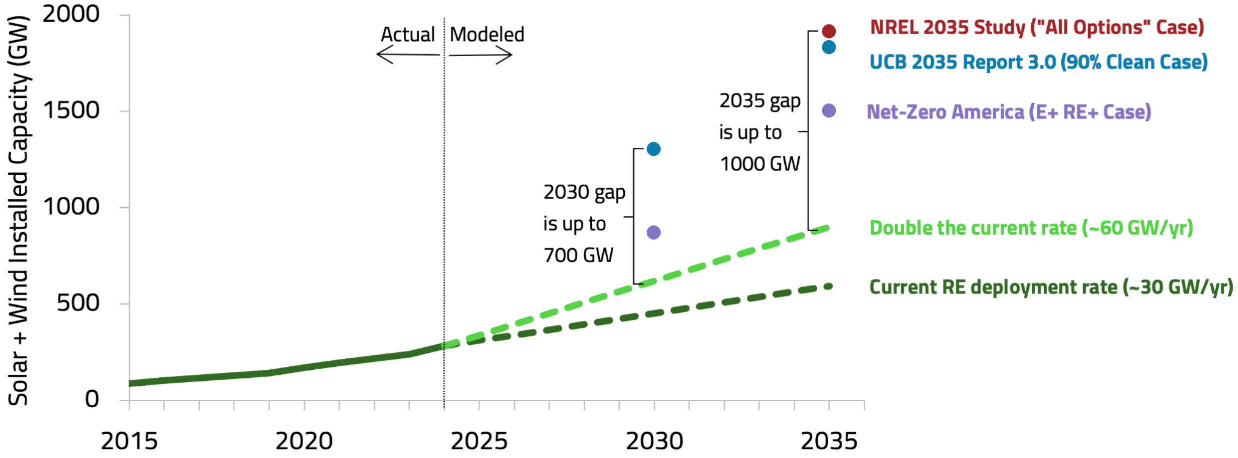

Figure 1: The US is headed toward a significant shortfall in clean energy, projected to reach around 1,000 GW by 2035 even with a doubling of the current deployment rate. Actual values for 2015-2023, projected values for 2024, extrapolated values for 2024-2035, and modeled values for 2030 & 2035 from major studies (7-9).

A promising strategy for accelerating renewable energy deployment is to leverage existing grid infrastructure through interconnection sharing. Also known as surplus interconnection, repowering, cable pooling, or hybridization, it would involve the expedited addition of RE and/or battery storage capacity at or in close proximity to existing power plants, allowing the RE capacity to share the existing grid access point without surpassing the original interconnection capacity limits - as shown in Figure 2. The strategy would maximize the utilization of existing grid assets and effectively bypass the lengthy conventional interconnection queue process. Policy paves the way forward for interconnection sharing at existing facilities under Order 845 from the Federal Energy Regulatory Commission (FERC), which requires transmission providers to establish an expedited process for interconnection customers to utilize or transfer surplus interconnection service at existing facilities. While the subsequent analysis focuses on adding RE to operational fossil plants through surplus interconnection, the basic premise of leveraging existing grid infrastructure would likewise be valuable for retiring power plants through generator replacement, enabling new, low-cost renewable and/or battery storage capacity to be added at the site of retiring power plants. A prime candidate for this is the nearly 70 GW of coal-fired capacity that is scheduled for retirement between 2024 and 2030 (10).

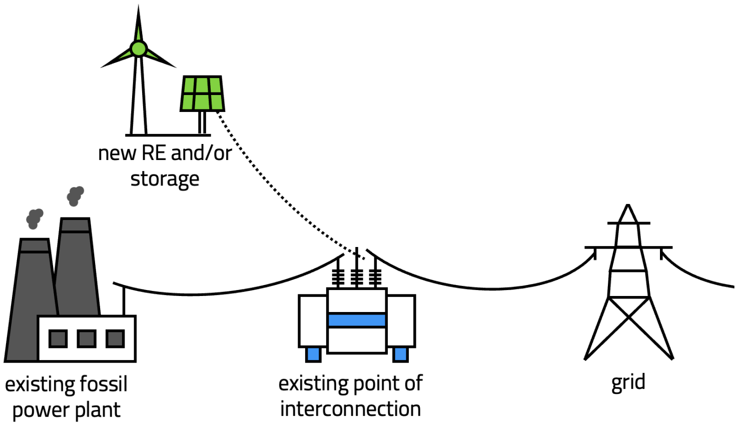

Figure 2: Schematic of renewables and/or storage sharing the interconnection with existing fossil power plants.

The Growing Challenge of AI Infrastructure Energy Demand

The rapid expansion of artificial intelligence infrastructure is creating unprecedented demands on the United States power grid. Morgan Stanley Research projects U.S. data center power consumption will escalate from 160 terawatt-hours (TWh) in 2023 to 337 TWh by 2027, with AI-specific power demand growing at a 105% compound annual growth rate (4). By 2030, data center power consumption could reach 450 TWh, constituting 10.6% of total U.S. grid capacity. According to EPRI, U.S. data centers would increase from approximately 4% of total U.S. electricity consumption today to between 4.6% and 9% by 2030 (11).

Major technology companies are pursuing strategic partnerships with nuclear facilities to secure reliable clean power. Microsoft is funding the restoration of decommissioned nuclear facilities, while Amazon has acquired a nuclear-powered data center near the currently operating Susquehanna Nuclear facility. However, when large technology companies secure substantial portions of existing clean energy capacity, it reduces availability for other grid users, potentially increasing reliance on fossil fuels elsewhere if clean energy development cannot match growing demand.

Interconnection sharing offers a solution by enabling rapid integration of renewables through existing interconnection points. By reducing project deployment times from 4-5 years to 1-2 years, this approach enables faster expansion of cheap clean energy capacity rather than redistribution of existing resources—essential for maintaining U.S. technological leadership in artificial intelligence development.

Clean energy cost declines and IRA incentives have substantially augmented the economic viability of the opportunity. Three factors in particular stand out in the IRA: generous Production Tax Credits (PTCs) for RE generation; an enhanced 10% bonus on PTC as well as an Investment Tax Credit (ITC) for RE projects located in energy communities; and an Energy Infrastructure Reinvestment (EIR) program that offers low-cost loans for communities to repower or repurpose existing energy infrastructure (12). These factors increase the likelihood that the levelized cost of RE near existing fossil power plants will be lower than the existing plants' operating costs, enabling plant owners to - after considering operational constraints like ramp rates - back down their fossil plants and send out clean power during RE generation hours, reducing the all-in cost of delivering power at the point of interconnection. This is reinforced by Figure 3, which shows how both renewables' Levelized Cost of Energy (LCOE) as well as Power Purchase Agreements (PPAs) prices have declined in recent years, reaching a generation-weighted $30.5/MWh with tax credits and $24/MWh for projects beginning commercial operation in 2023, respectively (1). This is either competitive or below the median variable costs of conventional generation sources - and renewable costs are projected to continue to decline.

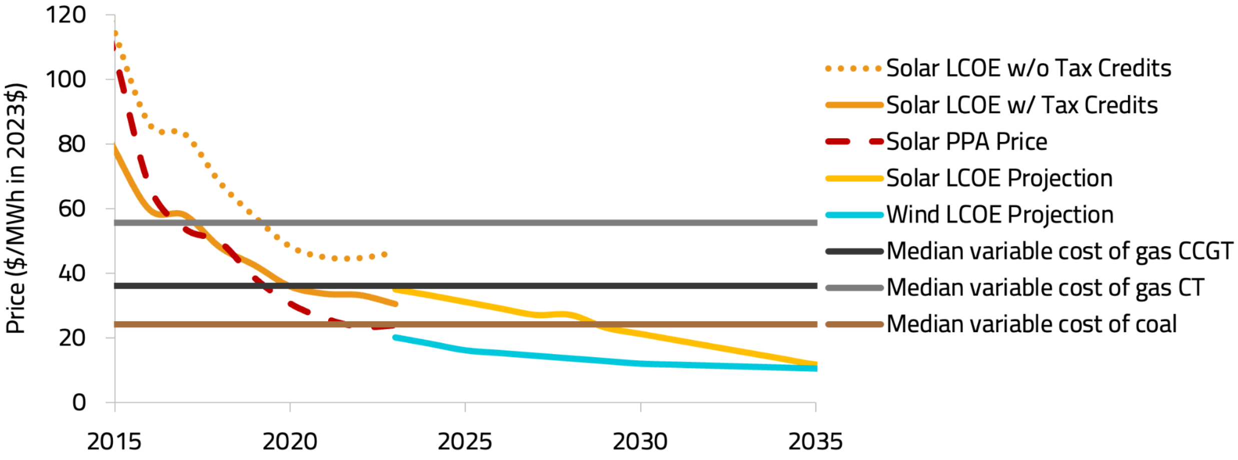

Figure 3: The costs of new solar and wind are falling below the costs of coal and gas plants, creating an opportunity to cost-effectively swap their generation with clean energy. Historical solar LCOE and PPA prices from (1), projected solar and wind LCOE from (13). Historical LCOE and PPA prices reflect the year in which commercial operation commenced.

Although the idea of interconnection sharing has been discussed for years, it was perceived as a limited case-by-case opportunity that required the highest RE resource quality (14-18). However, the falling costs of RE combined with recent policy developments have sparked new commercial interest, particularly in integrating solar at existing fossil power plants; these projects indicate that interconnection sharing offers significant advantages with regards to faster deployment, avoided interconnection costs, improved infrastructure utilization, retaining tax revenue and jobs in host communities, new revenue streams through portfolio diversification for fossil asset owners, and lowering electricity costs and thus consumer bills. Overall, the strategy presents a promising, unifying pathway for accelerating clean energy deployment by engaging stakeholders who might otherwise resist the energy transition by aligning their economic interests with decarbonization efforts. Here, we build upon previous studies with the latest data to quantify the opportunity of interconnection sharing, which with appropriate policy and regulatory support, could be a mainstream strategy for integrating clean electricity sources at speed and scale.

Finding #1: The total hyperlocal RE potential around US fossil power plants is over 15,400 GW

To quantify the potential for leveraging the interconnection of existing fossil plants, we first estimate the total resource potential of solar and wind in close proximity to existing fossil power plants. While previous studies assessed the RE potential over a large radius, i.e. 45 km (18), in order to robustly make the case there is sufficient local RE that can share existing interconnection points, we use a considerably tighter i.e. 10x10 km (6x6 mile) square buffer zone around the existing power plant, reflective of commercial activity in the US today. In practice, this means the maximum spur line distance between the RE facility and the existing point of interconnection would be less than 10 km (6 miles), which also minimizes the complexity associated with the permitting of the spur line. Within each buffer zone, we assess the potential for RE development of each 30x30m (100x100 ft) parcel of land through high-resolution satellite imagery and applying several exclusion criteria (for more details, see Methods). We find that the total hyperlocal RE potential within the 10x10 km buffer zone near the 1400 existing fossil power plants in the contiguous US is over 15,400 GW.

Estimating Deployable Hyper-Local Renewable Energy Potential by Considering Multiple Exclusions

Renewable energy (RE) deployment is increasingly facing siting challenges. To arrive at a realistic estimate of deployable potential, we sought to replicate the criteria that RE project developers typically use to select suitable land for deployment considering these challenges. We applied 50+ exclusion criterias, grouped into four main categories:

1. Physical Site Characteristics: We excluded areas based on incompatible land cover types (including urban development, water bodies, forests, and mangroves), excessive slope gradients, and elevation constraints that would preclude RE development.
2. Protected Areas: All locations with environmental protection status or development restrictions were removed from consideration.
3. Infrastructure Density: We eliminated sites where built infrastructure exceeded 30% of the land area within a 6-mile (10x10 km) buffer zone around existing power plants, recognizing that dense development patterns typically preclude cost-effective RE deployment.
4. Regulatory Restrictions: Areas subject to local ordinances prohibiting wind development were excluded from wind potential calculations, reflecting current regulatory limitations.

Out of a total of 1,404 power plants, 155 plants are entirely excluded due to having more than 30% built infrastructure within a six-mile buffer zone, affecting plants such as peaker plants in the Los Angeles Basin. We also excluded areas where local prohibitions prevent RE deployment, impacting approximately 5% of the plants in our analysis.

After applying these exclusions, of the remaining 1220 plants, 1099 have renewable potential that exceeds their interconnection capacity by more than five times, indicating significant opportunities to maximize the utilization of interconnections through increased renewable deployment.

From this total, we next evaluate the technical and economic viability to quantify the actionable RE integration potential as well as the RE needs for a least-cost power system, as shown in Figure 4.

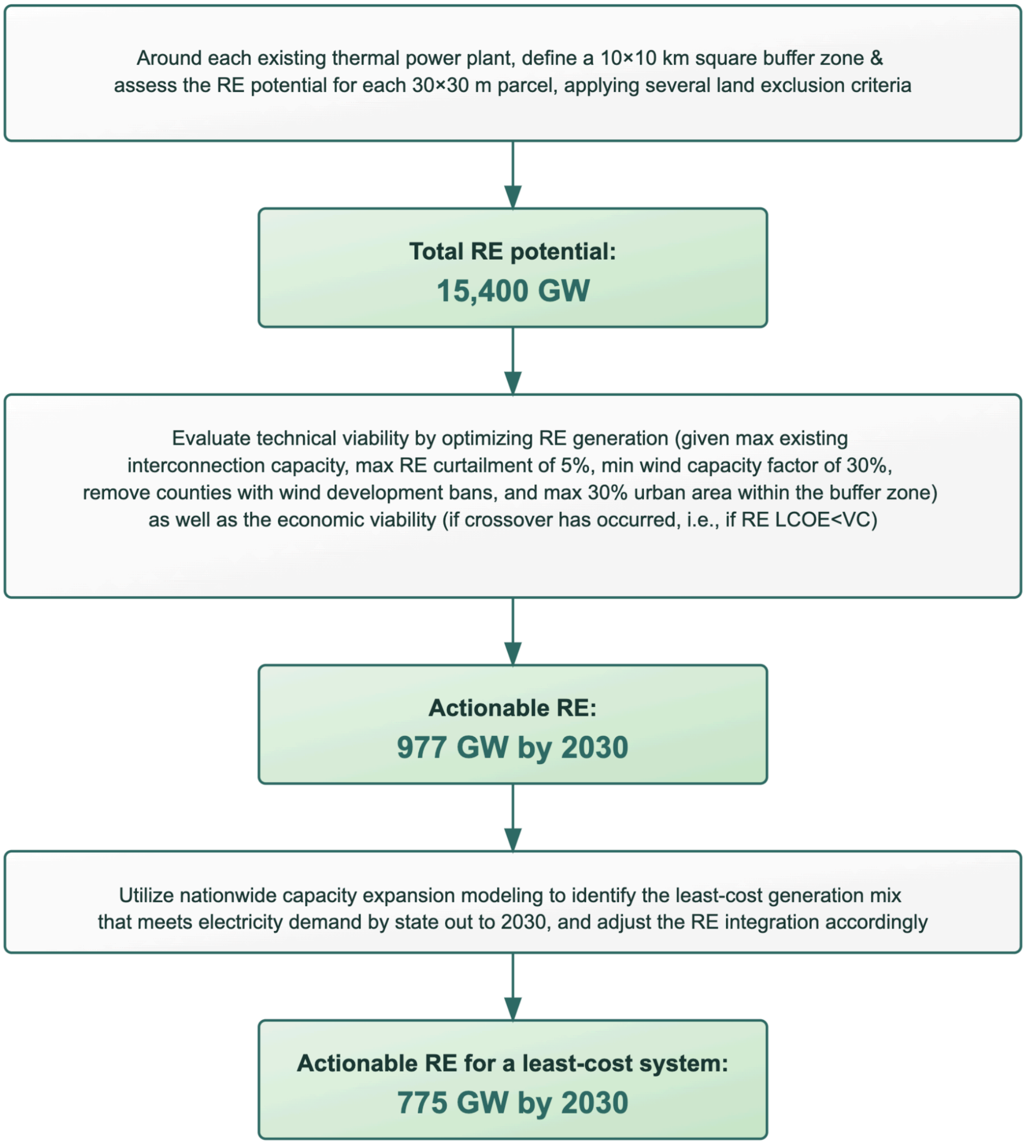

Figure 4: Summary of methods and results.

Finding #2: For over 75% of existing fossil power plants, the RE LCOE is lower than the plants' variable costs today

Despite this tremendous potential, the RE integration potential at existing interconnection is likely significantly lower as a result of several constraints which we subsequently apply. For one, for interconnection sharing to be economically viable, crossover must have occurred - that is, the LCOE of local RE must be lower than the variable cost (VC) of the existing fossil power plants, particularly those that operate at high capacity factors. To calculate the VC, we take the fuel cost (calculated based on the 7-year historical average of state-level costs for coal or gas, from the Energy Information Administration (EIA)) plus variable operation and maintenance (O&M) costs (from ReEDS) (for more details, see Methods). This analysis is performed on a unit level for the 4600 individual units at the 1400 existing fossil power plants in the US, recognizing that fuel type and prime mover may not necessarily be homogeneous across all units within the same plant.

As shown in Figure 5a-b, we find that solar crossover has arrived for 75% of the 700 GW of existing fossil interconnection and wind crossover has arrived for 80% of the 700 GW of existing fossil interconnection in the US today. Crossover is projected to arrive by 2030 for nearly all existing fossil power plants as RE costs decline further, as shown in Figure 5c-d. The cumulative interconnection capacity of existing fossil power plants that has crossed over can be seen on an annual basis in Figure 5e-f, indicating that an average of 8 GW of wind and 30 GW of solar crosses over per year until 2030. This economic crossover leads to a fundamental shift in the conventional operational paradigm: once the local RE LCOE falls below the VC of fossil generation, renewable generation should be prioritized when available, accounting for the operational constraints of existing plants (i.e., ramp rates or minimum run rates). Under this paradigm, the fossil assets effectively become capacity resources which only operate when renewable generation is insufficient to meet demand or during extreme situations such as severe weather or contingency events, when grid reliability is paramount. Significant savings can also be realized by power plant owners through prioritizing renewable generation during solar and wind hours while maintaining fossil capacity for periods when renewables are not generating.

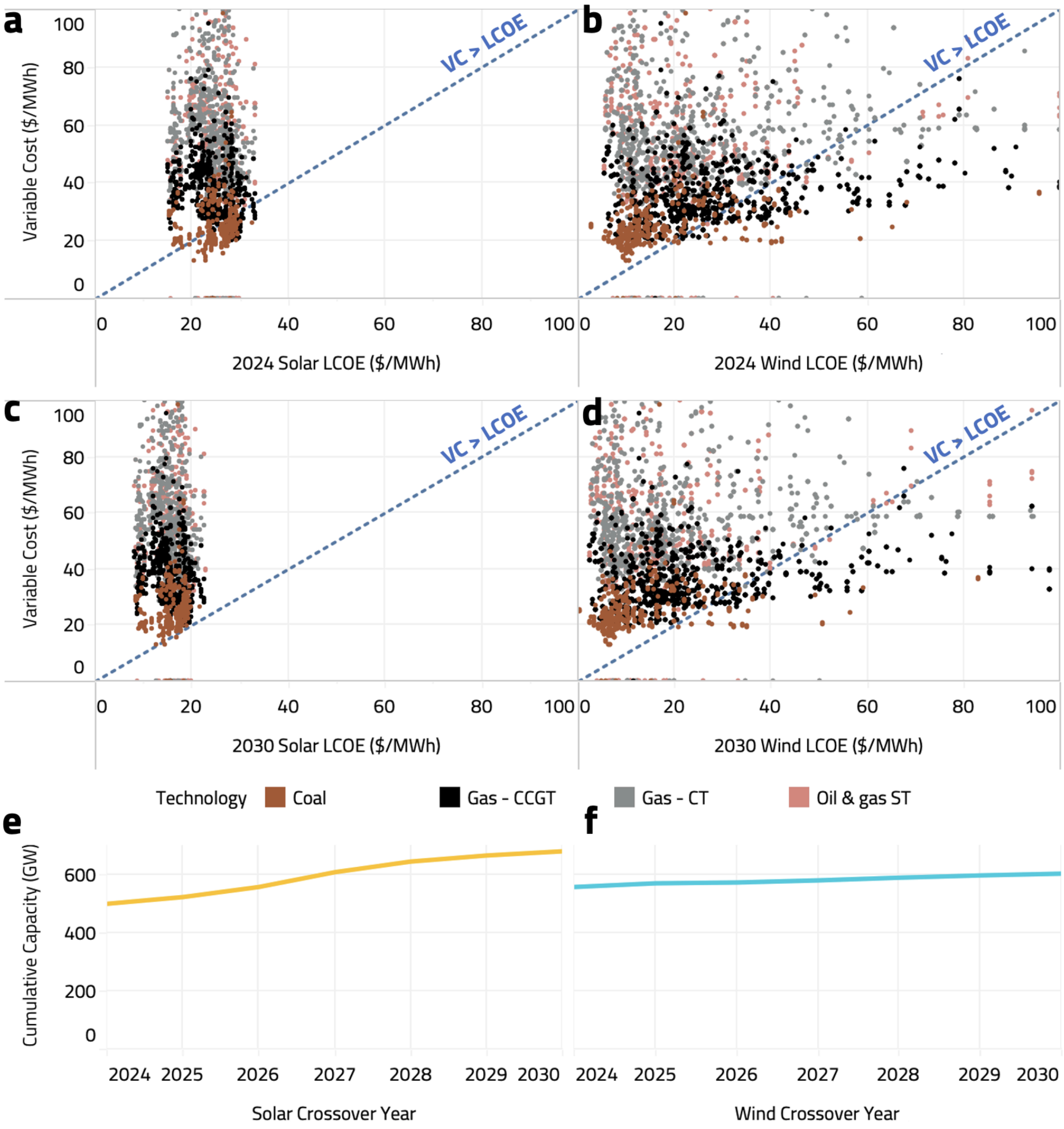

Figure 5: RE cost crossover has arrived for over 75% of existing fossil interconnection in the US today. (a-d) Cost of local solar and wind compared to the variable cost (fuel cost plus variable O&M) of existing fossil power plants, both in 2024 and 2030. Crossover occurs when the local RE LCOE is lower than the unit-level variable cost of existing fossil power plants. **(e-f)** The cumulative interconnection capacity of existing fossil power plants that is crossed over as a function of year for both solar and wind.

Finding #3: Around 1000 GW of solar and wind is economically viable by 2030 for integration into existing fossil interconnection

We next optimize the capacity of solar and wind that is not only economically viable, but also technically viable for potential integration at each existing fossil plant. To do so, we take hyperlocal hourly annual solar and wind profiles at each existing fossil plant and maximize annual RE generation (solar + wind) subject to constraints including an interconnection capacity limit (to ensure that instantaneous RE generation does not exceed the existing interconnection capacity) and an annual curtailment that is no higher than 5% (to maintain economic viability). We additionally exclude the plant if built-up area exceeds 30% of the area within the 10x10 km buffer zone around the plant, as this indicates significant cost implications and potential challenges in land acquisition for RE development. The local RE resource quality is benchmarked against actual projects under development in the vicinity; while solar resources are generally comparable, for wind we apply an exclusion criterion to only consider local wind potential with a minimum capacity factor of 30%. This ensures that integrating RE projects near existing fossil power plants would not compromise on quality nor cost compared to integrating RE with new grid interconnection. In addition to these technical and economic constraints, wind development is excluded in counties with existing wind development moratoriums.

The RE potential that is simultaneously technically and economically viable comprises the 836 GW of actionable RE potential near the interconnection of existing fossil power plants today, which increases to 977 GW by 2030 as the costs of new RE decline. If integrated, this actionable RE potential could nearly double the US generation capacity. The evolution of the actionable RE integration between 2024-2030 can be viewed by ISO/RTO in Figure 6, highlighting significant opportunity in PJM and MISO. The opportunity in PJM is particularly acute given their significant challenges in maintaining resource adequacy due to surging electricity demand that is indicating a growing risk of a multi-GW capacity shortfall over the next 5 to 10 years. This underscores the potential of interconnection sharing both with existing fossil assets as well as at the site of retiring facilities as well, to help accelerate the integration of new resources, meet projected load growth and support grid reliability.

Figure 6: Substantial opportunity for integrating RE at existing interconnection exists in PJM and MISO, followed by ERCOT, SPP and FRCC.

Deploying this actionable RE potential in its entirety would require an unprecedented effort that is currently hindered by many practical barriers - including the siting and permitting of RE projects, equipment procurement, the availability of labor for installation, financing, etc. - which require individual attention to substantially accelerate the RE deployment rate. Another outstanding question regarding realistic integration of the actionable RE potential pertains to the breakdown by type of RE, and specifically, the actionable capacity of solar versus wind. Within the past five years, the annual capacity addition of onshore wind has averaged 10 GW/year, while solar has averaged nearly double that at 18 GW/year. Further, the magnitude of annual capacity additions have been trending downwards for onshore wind, while solar has been trending upwards, reflecting solar's relatively lower complexity with regards to siting, permitting and installation logistics over wind.

Given these deployment trends and the significant role of fuel prices in determining economic viability, we examine two key scenarios: one considering both solar and wind integration potential, and another focused solely on solar deployment. We analyze these scenarios across a range of state-specific fuel prices to understand how price volatility affects integration potential over time.

Sensitivity Analysis

To assess the robustness of our findings, we conducted sensitivity analyses using state-specific historical fuel price volatility. For each state, we established three scenarios based on 7-year fuel price data: a base case using the state's average price, and low and high cases set at one standard deviation below and above that state's mean. Natural gas prices in the base case ranged from $2.41 to $7.54/MMBtu (mean: $4.26/MMBtu), with the low scenario ranging from $1.02 to $6.75/MMBtu (mean: $2.40/MMBtu) and the high scenario from $3.74 to $10.00/MMBtu (mean: $6.11/MMBtu). Similarly for coal, base case prices varied from $1.25 to

$8.07/MMBtu (mean: $2.56/MMBtu), with the low scenario ranging from $1.20 to $5.45/MMBtu (mean: $2.15/MMBtu) and the high scenario from $1.31 to $10.70/MMBtu (mean: $2.98/MMBtu).

As shown in Figure 7, while state-level fuel price variations significantly influence the total RE integration potential, the opportunity remains substantial across all scenarios. In 2024, the integration potential ranges from 564 GW in the low fuel price case to 932 GW in the high fuel price case, with the base case at 837 GW. This range evolves to 681-979 GW by 2027, with base case at 921 GW and reaches 829-990 GW by 2030, with base case at 977 GW. Notably, the minimum potential grows consistently across years—from 564 GW to 829 GW—demonstrating that even in states with persistently low fuel prices, declining renewable costs drive increasing economic viability of RE integration.

This state-level sensitivity analysis reinforces the fundamental strength of leveraging existing interconnection for renewable integration. Even in states with consistently low fuel prices, the potential for over 800 GW of RE capacity integration by 2030 represents a transformative opportunity. The convergence of integration potential across scenarios over time, illustrated in the Figure 7, underscores how declining renewable costs progressively reduce the impact of state-level fuel price volatility on the economic case for RE integration. The narrowing range between scenarios—from 368 GW in 2024 to 161 GW in 2030—further demonstrates the increasing robustness of the RE integration opportunity as technology costs decline.

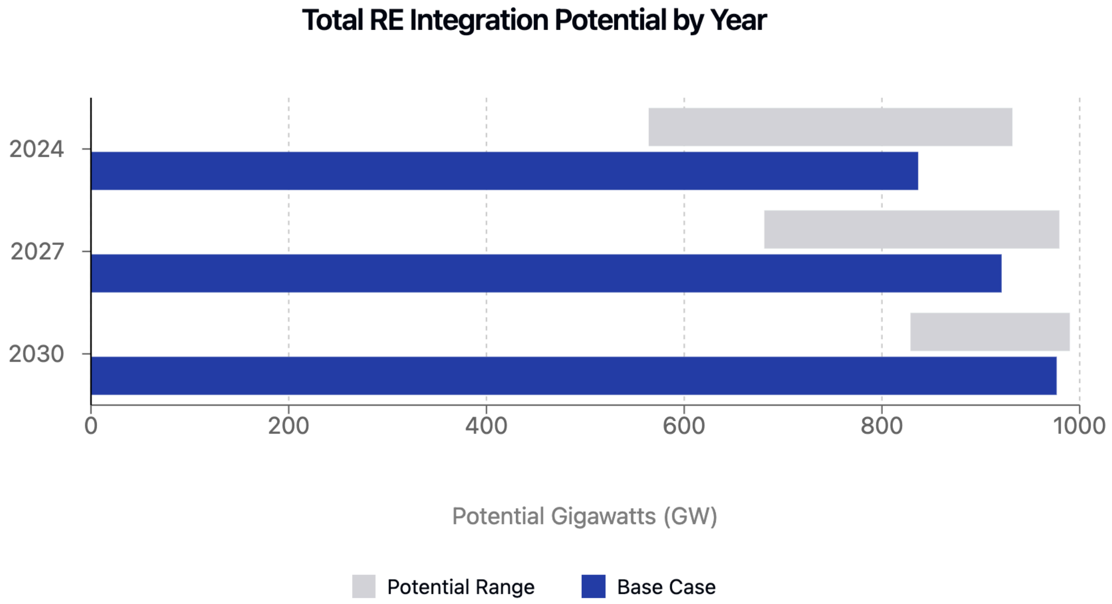

Figure 7: Total renewable energy integration potential across different fuel price scenarios (2024-2030). The range between high and low scenarios narrows from 368 GW in 2024 to 161 GW in 2030, demonstrating increasing resilience to fuel price variations.

To more closely align with current renewable deployment trends, we conduct a Solar-Only Scenario (SOS) analysis, reflecting the generally lower siting and permitting barriers faced by solar projects compared to wind. As seen in Figure 8, in the SOS base case, the integration potential begins at 499 GW in 2024, grows to 614 GW by 2027, and reaches 693 GW by 2030. The potential shows significant sensitivity to fuel price variations, particularly in earlier years. Under high fuel prices (one standard deviation above state means), the potential increases to 608 GW in 2024, 681 GW in 2027, and 700 GW in 2030. Conversely, with low fuel prices (one standard deviation below state means), the potential starts at 281 GW in 2024, rises to 384 GW by 2027, and reaches 567 GW by 2030.

The impact of fuel price variations on solar integration potential demonstrates a clear pattern of convergence over time, as also shown in Figure 8. The potential range is widest in 2024, spanning 327 GW (from 281 GW to 608 GW), but narrows substantially to 297 GW by 2027 (from 384 GW to 681 GW) and further contracts to 134 GW by 2030 (from 567 GW to 700 GW). This convergence pattern mirrors our findings from the combined solar and wind analysis, suggesting that while near-term solar deployment opportunities are significantly influenced by fuel price fluctuations, the long-term integration potential becomes increasingly robust as solar costs continue to decline. Even in the most conservative scenario with persistently low fuel prices, the potential for solar integration reaches 567 GW by 2030, representing a substantial opportunity for clean energy deployment.

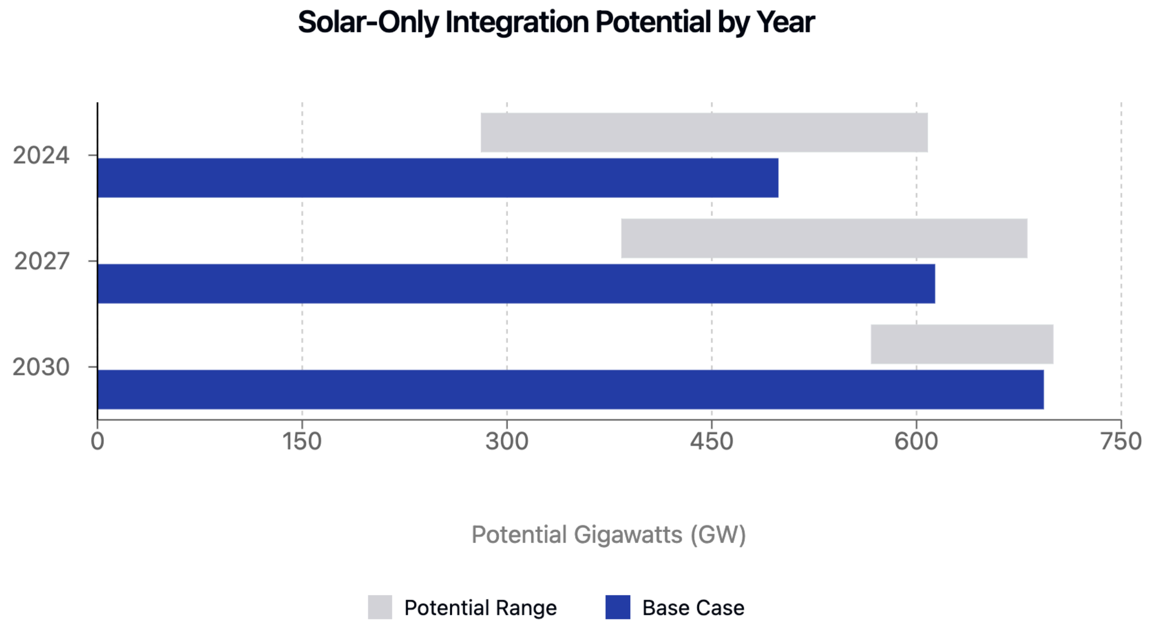

Figure 8: Solar-only integration potential across different fuel price scenarios (2024-2030). Similar to total RE, the range between scenarios contracts from 327 GW in 2024 to 134 GW in 2030, showing increasing economic viability over time.

Interconnection Cost Savings

Utilizing existing interconnection has the added benefit of avoiding much of the costs of interconnection, including network upgrades. These costs have grown substantially in recent years, ranging from \$71-107/kW by ISO (19). This indicates that integrating the identified 1134 GW of renewable capacity at existing interconnection by 2030 could avoid approximately \$85 billion in interconnection costs compared to developing these projects at new interconnection points. These savings stem from both minimizing direct interconnection infrastructure investments and avoiding network upgrades by leveraging the existing system, representing a significant reduction in system costs.

Operational feasibility

To assess the operational feasibility of integrating RE capacity at existing interconnection and account for operational constraints of existing plants (i.e., ramp rates or minimum run rates), we conduct a detailed hourly dispatch simulation for an exemplary CCGT, California's La Paloma Plant (1048 MW), with an additional 1048 MW_{AC} of solar capacity at the same interconnection point. The combined solar and gas system was modeled to deliver flat block power daily, i.e. the most rigorous ramping and unit commitment scenario, requiring the CCGT plant to cycle each day within operational constraints that are aligned with CAISO’s model parameters. The analysis indicates that integrating solar capacity alongside the CCGT at the existing interconnection point is technically feasible and fully adheres to operational constraints - including ramping, technical minimum levels, and minimum up and down times - and maintains solar curtailment at only ~5%. Further investigation is necessary to evaluate the long-term impacts of daily cycling on CCGT equipment durability.

Finding #4: Leveraging existing interconnection can help deliver a least-cost power system in over 35 states

Although around 1000 GW of actionable RE integration is assessed on a hyperlocal plant-level, from a broader system perspective, the RE required for a least-cost system is likely to differ. To evaluate this, we utilize a widely-used high-resolution transmission and generation capacity expansion model, the Regional Energy Deployment System (ReEDS) (20). The model optimizes the least-cost generation mix that meets the projected electricity demand for each of the model's 134 zones in the contiguous US, accounting for current policy such as IRA incentives as well as future technology cost declines. We compare the resulting least-cost renewable capacity needs by 2030 with our estimated interconnection sharing potential at the state level in order to ensure our estimates align with least-cost system needs while simultaneously identifying states where interconnection sharing could significantly contribute to meeting renewable deployment targets. Where actionable RE through interconnection sharing exceeds the least-cost requirement for a state, we constrain it to that requirement; while in states where our estimated potential falls below the least-cost requirement, we maintain our original estimate as it represents the realistic ceiling for interconnection sharing in that region. After applying these adjustments across all states, our analysis indicates that by 2030, interconnection sharing could enable the economical integration of 775 GW of renewables, helping to deliver the majority of RE needs for a least-cost power system in 38 states as shown in Figure 9.

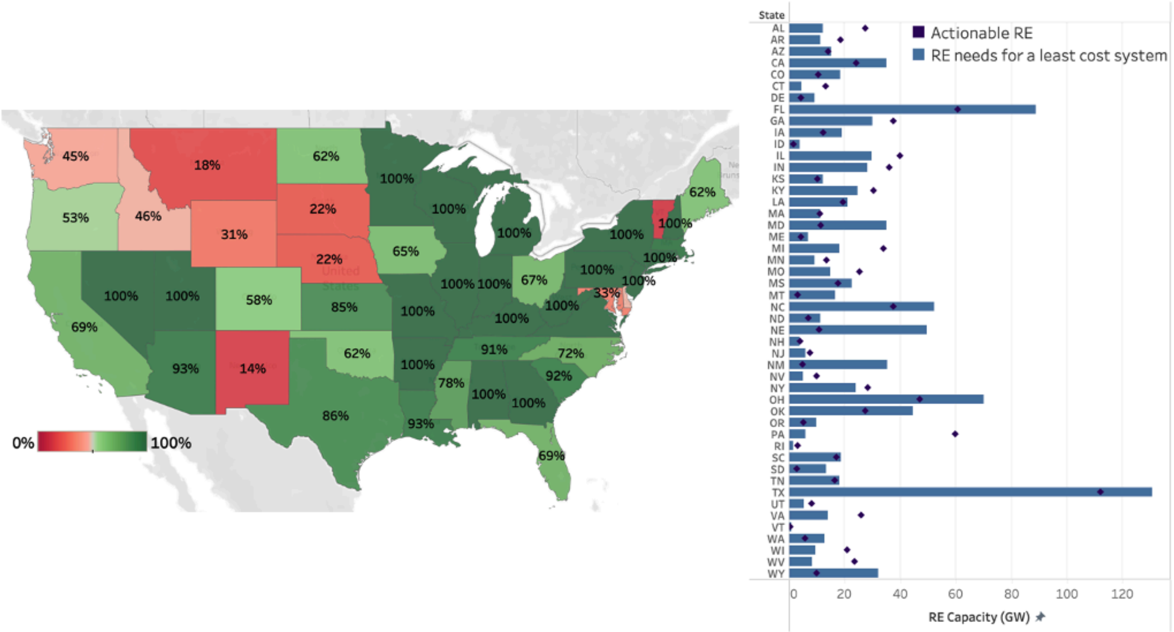

Figure 9: Leveraging the interconnection of existing fossil power plants can help deliver a least-cost power system in a majority of states. (a) Percentage showing the proportion of interconnection sharing in meeting the state's RE needs for a least-cost system in 2030. (b) State-by-state breakdown of actionable RE versus the RE needs.

Finding #5: More than 200 GW of existing fossil capacity in the US is minimally utilized and has high operating costs

The greatest immediate opportunity for interconnection sharing lies with existing fossil power plants that are either or both expensive to operate (with high variable costs) or minimally utilized (with low capacity factors). For instance, in 2023, over 200 GW of US fossil capacity did not use their interconnection for over 85% of hours in the year. The majority of this fossil capacity consists of peaker plants, run only to meet periods of peak residual demand. These peaker plants are typically natural gas-fired combustion turbines (CTs) as well as oil and gas steam turbines (STs) with higher heat rates and thus lower efficiencies compared to baseload fossil generation, namely natural gas-fired combined cycle gas turbines (CCGTs). Simultaneously, the vast majority of this minimally-utilized 200 GW of fossil capacity has operating costs that average approximately $20/MWh higher than intermediate and baseload fossil capacity that runs at higher capacity factors, as seen in Figure 10. On an aggregate level, the utilization of fossil power plants and their interconnection capacity would decrease as the RE penetration in the system grows.

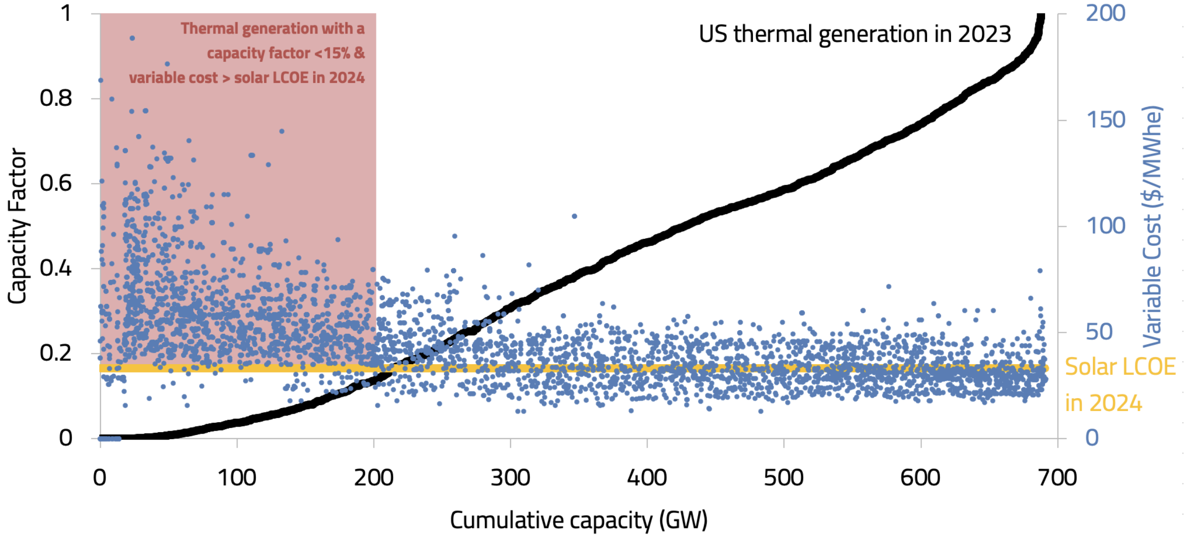

Figure 10: More than 200 GW of fossil capacity has a capacity factor below 15% and faces operating costs higher than the cost of new RE. The supply curve shows the capacity factor versus the cumulative installed capacity of US fossil plants, overlaid with the plants' operating costs from 2023 (composed of variable O&M plus fuel costs).

The high operating costs of these plants are in part due to, and further exacerbated by, their age. Coal-fired plants in the US average over 43 years, while oil-fired units average 42 years - which is likely beyond, or at least approaching, the lifespan of their original design specifications (21). This aging infrastructure not only contributes to operational inefficiencies at these plants, with older units requiring more fuel input per unit of electricity generated, but also monopolizes increasingly valuable interconnection points at a time when new renewable generators face significant challenges securing timely grid access. This presents an opportunity to improve the utilization of existing grid infrastructure through interconnection sharing, supporting the efficient integration of low-cost clean energy sources while maintaining the reliability services provided by existing generators.

Discussion

The technically feasible and economically viable opportunity for low-cost solar and wind to share interconnection with existing fossil plants totals around 1000 GW by 2030, with the potential to nearly double US generation capacity. This strategy benefits all stakeholders involved, as seen in Figure 11. First, it helps to rapidly deliver clean and low-cost electricity for consumers and the economy. From a power system perspective, integrating additional RE while retaining conventional fossil assets ensures the availability of sufficient generation capacity to serve rapid load growth, supporting grid reliability. The strategy diversifies the portfolios and revenue streams of power plant owners, creating net savings when lower-cost RE is used instead of conventional fossil generation during RE generation hours. RE developers meanwhile benefit from faster project realization, IRA incentives, and lower infrastructure costs due to avoided expenditure on interconnection equipment such as breakers and transformers. Further, it generates substantial investment and reduced pollution in energy communities, generating local tax revenue and providing employment opportunities to those who may otherwise experience a progressive decline as conventional fossil-fuel fired assets are scaled back.

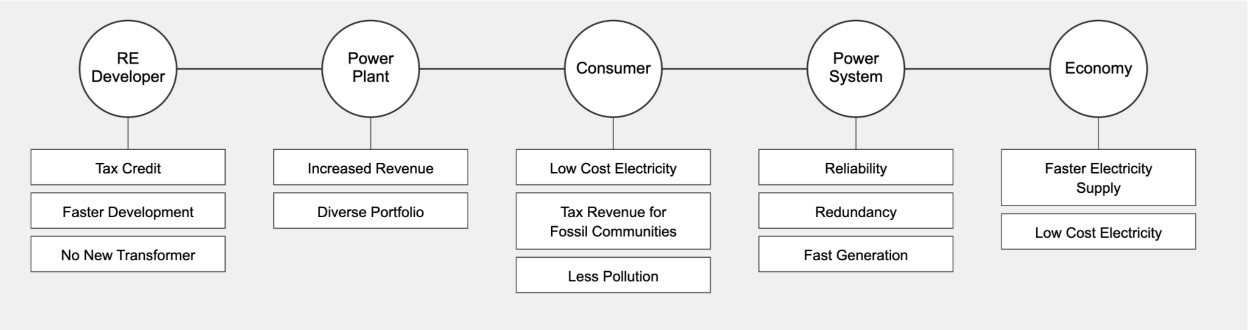

Figure 11: Interconnection sharing provides several benefits across various stakeholders.

Policy recommendations to accelerate RE deployment at existing interconnection

Although FERC Order 845 paves the way for capitalizing on the benefits of surplus interconnection, additional policy and regulatory support is required for this to become a mainstream strategy for integrating clean electricity sources at speed and scale. This is because surplus interconnection presents a significant opportunity, but also a significant deviation from the conventional interconnection process. While the interconnection process has notably been subject to substantial reform in recent years, the basic process involves an interconnection customer - i.e., a RE project developer - submitting a request for grid interconnection to the transmission provider, joining the queue of interested projects. These projects must undergo a series of system impact and facility studies that analyze if, and which, network upgrades are needed before the project can be brought online. The costs of these impact studies, as well as the identified network upgrades, are borne by the interconnection customer. In recent years, the number of projects in the queue has ballooned for a number of reasons: more distributed energy projects joining the queue, growing interest in developing RE with the support of tax credits, and an outdated process that has not kept pace with new requests. Yet if a project manages to successfully pass through, the interconnection customer signs an interconnection agreement with the transmission provider that stipulates terms of operation. In contrast, an interconnection customer interested in interconnection at an existing point of interconnection would follow a very different process.

Background on FERC Order 845

Issued April 2018, Section IV.C.3 of FERC Order 845 requires transmission providers to establish an expedited process for interconnection customers to utilize or transfer Surplus Interconnection Service (SIS) at existing generating facilities such that the total amount of interconnection service (and thus the combined generating output) at the Point of Interconnection (POI) remains the same and no network upgrades are required (22). While the existing interconnection customer or its affiliates has the priority to use SIS, it may be transferred to another interconnection customer. The required studies for SIS include reactive power, short circuit/fault duty, stability analyses, and potentially steady-state (thermal/voltage) analyses as necessary. Nearly all regions of the US comply with Order 845's requirements with the exceptions of ERCOT (which is not under the jurisdiction of FERC) and NYISO (which sought and was granted an independent entity variation), albeit with varied implementation. Generally, the SIS process significantly shortens the interconnection timeline (versus the recent average of 4-5 years for projects requiring new interconnection). However, surplus interconnection is, by definition, tied to the continued existence of the original interconnection customer's interconnection service; meanwhile, the process for adding new generation at retiring plant sites, referred to as the "generator replacement service," varies widely by region.

Today, there are 3 main barriers which hinder the full realization of this actionable potential: (1) limited awareness and/or motivation to capitalize on the large availability of economically viable RE potential near existing fossil power plants, particularly for the existing interconnection rights holders, (2) existing integrated resource and transmission planning processes do not consider RE deployment at existing interconnection, and (3) existing grid interconnection rules provide limited or insufficient support for interconnection sharing.

To address these barriers, policy recommendations for key entities include:

Federal Energy Regulatory Commission (FERC):

- Streamline Surplus Interconnection Service: Ensure a consistent surplus interconnection service framework, removing overly restrictive study assumptions, improving process functionality and including a streamlined procedure for SIS customers to be able to permanently retain interconnection rights following the retirement of the original interconnection customer.
- Harmonize Generator Replacement Rules: Ensure a consistent generator replacement framework across all regions that enables fast-tracking of new energy projects at the site of retiring facilities, for example based on MISO's existing model.
- Create Standardized Agreements: Consider requiring transmission operators to develop and implement pro-forma agreements (e.g., Monitoring and Consent, Conversion) to clarify and expedite interconnection transactions, reducing administrative complexities across RTOs.
- Efficiently allocate existing interconnection rights to lower costs and protect consumer interests. Develop a regulatory pathway to fairly compensate current rights holders while establishing a system for efficient grid access allocation that promotes improved utilization, cost reduction, and competition.
- Enhance Transparency: Introduce open processes to transfer interconnection rights and prevent capacity hoarding, considering the creation of a clearinghouse, addressing concerns over "capacity squatting" and enabling fair access to interconnection capacity.

ISOs/RTOs:

- Streamline Surplus Interconnection Service: Ensure a consistent surplus interconnection service framework, removing overly restrictive study assumptions, improving process functionality and including a streamlined procedure for SIS customers to be able to retain interconnection rights following the retirement of the original interconnection customer.
- Enhance Generator Replacement Rules: Ensure a consistent generator replacement framework compatible with neighboring regions that enables fast-tracking of new energy projects at the site of retiring facilities, for example based on MISO's existing model; ensure this is harmonized to allow for continuation of interconnection service for SIS customers following the retirement of the original interconnection customer.
- Integrate SIS and generator replacement in long-term transmission planning: Consider renewable resources at existing interconnection points in the scenario planning under Order 1920.
- Enhance Transparency: Establish data portals and/or perform studies that highlight surplus interconnection opportunities to guide developers and load-serving entities (LSEs) in project planning.
- Facilitate Adoption: Consider developing a clearinghouse to enable market participants to offer surplus interconnection capacity to others, facilitating bilateral agreements.

- Standardize Contractual Agreements with Interconnection Customers: Consider developing standardized contractual agreements to establish the terms of operation of shared interconnection, particularly with surplus interconnection customers.

Public Utility Commissions (PUCs):

- Integrate SIS in IRPs and RFPs: Require utilities to include surplus interconnection and generation replacement capacity options in Integrated Resource Planning (IRP) and Requests for Proposals (RFPs) to prioritize cost-effective renewable deployment that can leverage existing infrastructure.
- Assess Existing Interconnection Potential: Direct utilities to study clean energy potential at existing fossil power plants, promoting rapid RE deployment and cost savings by avoiding additional interconnection and transmission expenses.

State Legislators:

- Mandate SIS and Generator Replacement in Planning: Pass legislation requiring that PUCs assess surplus interconnection and generation replacement capacity as part of generation planning processes, improving grid resilience and accelerating renewable deployment for consumer benefit.
- Address Siting and Workforce Development: Allocate funding to communities with fossil infrastructure to conduct studies on local siting as well as the economic, environmental, and community benefits of utilizing existing interconnection, and support workforce reskilling programs to transition labor from retiring plants to new clean energy roles.

Load-Serving Entities (LSEs):

- Prioritize Existing Interconnection in Resource Planning: Assess surplus interconnection and generation replacement capacity opportunities in resource planning and RPS compliance, focusing on renewable development at existing interconnection points to minimize infrastructure costs and increase speed of interconnection.
- Conduct Cost-Savings Studies: Analyze and communicate potential savings from integrating renewable energy at existing sites, demonstrating reduced costs through avoided interconnection and transmission needs.
- Partner with Legacy Generators: Collaborate with legacy generators to co-develop renewable and storage projects at existing interconnection, using shared interconnection agreements to share benefits and meet clean energy goals effectively.

Generators with Interconnection Rights:

- Monetize Interconnection Capacity: Explore opportunities to monetize unused interconnection capacity, either through direct sale or auction, thereby creating new revenue streams and supporting renewable deployment.
- Partner with Renewable Developers: Develop partnerships with renewable energy and storage developers to utilize surplus interconnection rights, providing access to existing infrastructure while supporting grid reliability and clean energy growth.

Future work

Exploring the Potential of an Integrated Renewable, Repower (Surplus Interconnection), and Reconductoring (RRR) Strategy for Rapid and Extensive Deployment of Low-Cost Electricity

There can be several possible extensions of this work. First, evaluating the additional storage and renewable energy (RE) deployment potential by sharing grid access with existing RE plants, which currently have a capacity of about 250 GW. There is potential to add 4-6 hours of storage at a similar capacity (250 GW), thereby adding significant new firm capacity to the U.S. grid while creating opportunities for an additional 250-500 GW of RE deployment that can share the same interconnection. Several RE projects are already adopting such strategies.

The US has one of the world's largest transmission networks, with over 600,000 miles of high-voltage transmission lines crisscrossing the country, and vast amounts of economical RE potential exist in the vicinity of these lines. However, in 2023, the country added only around 60 miles of new high-voltage transmission lines, contributing to a five-year total of just 2,500-3,000 miles. The grid primarily uses wires based on technology that is more than 100 years old. Our research has shown that the U.S. can double its transmission capacity and meet over 80% of its transmission needs by rewiring the grid with commercially available advanced conductors (i.e., reconductoring), which can carry twice the amount of electricity. This upgrade can be completed much faster and more economically than building brand-new lines, bypassing the lengthy permitting processes required for new infrastructure.

With reconductoring, which can potentially double grid capacity, the interconnection capacity of the existing power generation infrastructure (exceeding 1,000 GW) can be significantly increased (up to a doubling). This would enable more interconnections, leveraging existing infrastructure while reducing costs and timelines. Thus, combining a focus on renewables, re-powering (surplus interconnection), and a reconductoring strategy can pave the way for low-cost, clean energy abundance.

Methods and Data Summary

In order to estimate the technical feasible and economically viable RE integration potential by sharing grid access with existing fossil plants we used the following steps.

First, we *estimated the renewable energy resource availability* within the vicinity (within a 6-mile buffer zone around each power plant) that could share the existing grid access. In assessing RE availability, we considered over 50+ criterias to replicate the exclusion criteria typically used by developers, including physical constraints, environmental protections, local ordinances limiting RE deployment, and difficulty of deploying RE near urban areas. Even after applying these considerations, we found that over 80% of the fossil power plants have more than five times the renewable potential compared to their current interconnection capacity limits

The second step was *to evaluate the economic viability of RE sharing grid access* with existing fossil plants. *We identified plants where the LCOE of local renewables is lower than the operating costs (fuel costs and variable o&m costs) of fossil plants.* In such cases, it would be economically beneficial for these plants to allow renewables to access the grid, as this would enable them to save costs by prioritizing renewable generation over fossil-based electricity when available. This analysis involved collecting detailed data on the operating costs of over 1,400 power plants and estimating the local LCOE for renewables near each of these plants. We also considered all the applicable tax incentives and savings in interconnection costs that arise from using the same interconnection.

The third step was to estimate for plants where the LCOE of local RE is lower than the operating costs of power plants, *how much renewable energy can be integrated to maximize the use of existing interconnection* while considering its current limit. For each of the plant locations, we estimated the optimal portfolio of solar wind which maximizes interconnection usage (solar + wind generation) while limiting the curtailment to below 5%. We conducted a dispatch simulation for a power plant using actual operating constraints and confirmed that technical operational limitations did not increase curtailment beyond the 5% threshold.

The fourth step was to *determine what share of the total renewable capacity needed in the future, based on a least-cost planning exercise, could be met through deployment at existing interconnections.* To do this, we conducted a national generation capacity expansion study using NREL's ReEDS model, which simulates 134 sub-regions in the U.S., to identify the least-cost capacity mix of solar and wind. We then compared how much of this projected capacity could be met through deployment at existing interconnections.

The following discussion offers more details on each of these steps.

1. Estimating Local Renewable Resource Availability

Estimating Local Renewable Energy Potential

To assess the solar and wind potential near existing fossil power plants, we conduct a geospatial analysis integrating multiple high-resolution datasets. For each plant, we define a 6x6 mile (10x10 km) square buffer zone, representing the area within which RE projects could feasibly connect to existing interconnection infrastructure. We create a comprehensive exclusion dataset to exclude unsuitable areas for RE development, integrating land cover, protected areas, elevation, and slope data. Key data sources include:

- Protected Areas: US Geological Survey's Protected Areas Database (PAD-US) to exclude national parks, wildlife refuges, and other conserved lands (23).
- Elevation and Slope: Copernicus Digital Elevation Model (30 m resolution) to exclude areas with high slopes and elevation (24).
- Land Cover: European Space Agency's WorldCover 10 m dataset to exclude urban areas, water bodies, wetlands, dense forests, etc. (25).

For the remaining suitable areas within each buffer zone, we estimate potential solar and wind energy capacities using standard conversion factors: 50 MW per square kilometer for solar PV and 6 MW per square kilometer for wind. These factors reflect typical utility-scale installation densities and provide an estimate of the maximum buildable RE capacity near each fossil plant.

2. Evaluating the Economic Viability of Renewable Energy Sharing Grid Access

Estimating power plant operating costs

We develop a detailed dataset of existing fossil power plants in the US using data from the US Energy Information Administration (EIA) Forms 860 and 923 for the year 2023 and 2022 (26,27). This dataset includes information on plant location, capacity, fuel type, operational characteristics, heat rates, and variable operating costs. To enhance accuracy, especially for heat rates, we incorporate cleaned data from the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) database, which provides validated engineering assessments based on actual performance data (20). Fuel price data were collected from multiple EIA sources. For natural gas, we took the recent 7-year average incorporating state-level monthly natural gas prices for electric power (supplemented with monthly state-level citygate prices if not available) (28). As oil & gas steam turbines are either mostly gas-based or dual-use technologies, their fuel costs are similarly based on natural gas prices. For coal, we used the recent 7-year average incorporating quarterly prices based on coal shipments to the electric power sector by plant state (29). Ownership structures were established using the Environmental Protection Agency's Greenhouse Gas Reporting Program (GHGRP), supplemented by EIA Form 860 data (26,30).

Estimate local LCOE of RE

We estimate hourly solar and wind generation profiles at each plant location using high-resolution meteorological data and a custom software tool developed for this study.

- Custom Simulation Tool: We developed a custom software tool that integrates established models (PySAM, PVWatts) with detailed system specifications to provide accurate hourly generation profiles for each site.
- Solar Generation:
  - Data Sources: We utilize the ERA5 dataset from the European Centre for Medium-Range Weather Forecasts (ECMWF), providing hourly data on solar irradiance, air temperature, pressure and wind speed at approximately 31 km resolution (31).
  - Simulation: We calculated three key solar irradiance measurements (Global Horizontal, Direct Normal, and Diffuse Horizontal) to model solar power generation. Using these measurements, we simulated the hourly output of a 1 MW solar farm equipped with single-axis tracking through the PVWatts model. To ensure accurate results, our simulation incorporated various technical parameters including the panels' tilt angles, directional orientation, system efficiency losses, and tracking system dynamics (32).
- Wind Generation:
  - Data Sources: We utilize NASA's MERRA-2 dataset for wind speed, direction, pressure and temperature at various altitudes (33).
  - Simulation: We employ the Python-based System Advisor Model (PySAM) to simulate wind power generation (34). The wind farm model simulates a detailed layout of 8 rows by 4, totaling 32 turbines, and accounts for wake effects and turbine interactions. Wind speeds are extrapolated to turbine hub heights, adjusted for local terrain and atmospheric conditions using high spatial resolution data from Global Wind Atlas.

These hourly generation profiles allowed us to estimate capacity factors for solar and wind at each plant location, accounting for temporal and spatial variations in resource quality.

Using the estimated capacity factors and cost parameters, we estimate the LCOE for solar and wind projects near each existing fossil power plant. Our cost and financial data were sourced from reputable industry and governmental reports to ensure accuracy:

- Cost Data:
  - Capital Expenditures (CAPEX) and Operational Expenditures (OPEX) come from NREL's Annual Technology Baseline (ATB) 2024 (13).

- Financial Parameters:
  - Weighted Average Cost of Capital (WACC) is calculated based on typical industry debt-to-equity ratios and costs of capital, from NREL's ATB 2024 (13).

    - Project Lifespan is assumed to be 30 years for both wind projects and solar PV projects, from NREL's ATB 2024 (13).

- Regional Adjustments:
    - Capital Cost Multipliers are applied to account for regional variations in installation costs, using data from the US EIA regional cost factors and NREL's ReEDS model (20).

- Incentives:
    - We account for federal and state incentives including the Investment Tax Credit (ITC) and Production Tax Credit (PTC) as outlined in the Inflation Reduction Act (IRA) of 2022 (12). These incentives were applied according to eligibility criteria and phase-out schedules.
    - We incorporate energy community designations to account for additional incentives available under the IRA. Energy communities are areas that have been economically affected by the decline of fossil fuel industries and are eligible for bonus tax credits to encourage renewable energy development. We identify these areas using data from the National Energy Technology Laboratory's (NETL) Energy Communities interactive map and the Internal Revenue Service's (IRS) Notice 2023-29 (35,36). This information was integrated into our dataset to adjust the LCOEof solar and wind for plants located within these designated areas.

We compare the estimated LCOE with the variable operating costs of individual units of the corresponding fossil plant, derived from fuel price data and heat rate metrics from EIA Forms 860, 923 and ReEDS. If the LCOE was lower than the plant's variable costs, we considered the plant to have "crossed over," indicating a cost-effective opportunity for replacing fossil generation with renewable energy. This analysis was conducted annually from 2024 through 2030 to capture changes in technology costs, fuel prices, and policy incentives over time.

Interconnection Cost Savings

To quantify potential cost savings from utilizing existing interconnection infrastructure, we analyze historical interconnection queue data from LBNL for completed projects from 2018 onwards across four Independent System Operators (ISOs): ISO-NE, MISO, PJM, and SPP (19). For each ISO, we calculate capacity-weighted average interconnection costs using only projects that achieved commercial operation, finding costs ranged from \$71/kW in SPP to \$107/kW in ISO-NE, with PJM at \$83/kW and MISO at \$85/kW. For regions outside these ISOs, we applied the mean interconnection cost from analyzed regions as a representative value.

The interconnection costs we analyze comprise two major components that could be largely avoided through co-location with existing fossil plants. The first component is Point of Interconnection (POI) costs - the direct expenses associated with physically connecting to the grid, including construction of interconnection substations and transmission line extensions (spurlines). The second component is network upgrade costs - the broader system-wide upgrades required to accommodate new generation, often involving reconstruction of transmission lines and substantial grid modifications.

Our interconnection cost estimates were based on projects that successfully reached commercial operation, as these represent the most realistic cost benchmarks. We excluded withdrawn projects from cost calculations, though notably these projects often faced significantly higher projected interconnection costs - frequently 2-3 times higher than completed projects - which likely contributed to their withdrawal. This conservative approach of using only completed project costs provides a lower-bound estimate of potential savings.

3. Estimating Renewable Energy Integration Potential to Maximize Use of Existing Interconnection Capacity

To determine the realistic integration potential of RE at existing interconnection points, we develop optimization models that maximize interconnection utilization while limiting curtailment and adhering to interconnection capacity limits. The model is formulated as follows:

Objective:

$$\text{Maximize} \quad \sum_{t=1}^{8760} (\text{solar\_generation}[t] + \text{wind\_generation}[t])$$

With the following decision variables:

- Installed solar capacity: solar_cap
- Installed wind capacity: wind_cap

Subject to the following constraints:

- Interconnection Capacity Limit, ensures that generation does not exceed the plant's maximum interconnection capacity

$$\text{solar\_generation}[t] + \text{wind\_generation}[t] \leq \text{interconnection\_max}$$

- Curtailment Limit, limiting annual curtailment to 5% of total potential generation to maintain economic viability:

$$\sum_{t=1}^{8760} (\text{solar\_curtailment}[t] + \text{wind\_curtailment}[t]) \leq 0.05 \times \sum_{t=1}^{8760} (\text{potential\_generation}[t])$$

- Curtailment Calculation, where $\text{solar\_cf}[t]$ and $\text{wind\_cf}[t]$ are the hourly capacity factors for solar and wind, respectively:

$$\text{solar\_curtailment}[t] = \text{solar\_cap} \times \text{solar\_cf}[t] - \text{solar\_generation}[t]$$
$$\text{wind\_curtailment}[t] = \text{wind\_cap} \times \text{wind\_cf}[t] - \text{wind\_generation}[t]$$

For plants where wind energy was viable (capacity factors above a threshold of 30%, consistent with current projects), we optimize both solar and wind capacities. For others, we optimize solar capacity alone. The optimization was performed using hourly data over a full year for each plant, processing in parallel batches to manage computational demands.

Actionable RE integration potential

The actionable RE integration was then estimated based on the RE potential that was both technically- and economically-viable: for each unit for which crossover has occurred, the plant-level technically-viable RE is adjusted by the proportion of the unit's capacity to the plant's total capacity.

4. Determining the Share of Total Least-Cost Renewable Capacity that Can Be Met by Deployment at Existing Interconnections

To align the actionable RE integration with actual power system needs, we conduct a comparative analysis using the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) model (20). ReEDS is widely used by the US Department of Energy and is considered an industry standard for projecting the optimal mix of generation technologies required to meet future electricity demand. By running ReEDS up to 2030, we obtain projections of the new capacity needed by technology—such as solar, wind, and gas—to meet the 2030 load, considering current US policies and hourly load profiles. We aggregate the ReEDS-projected new capacity installations of RE (solar and wind) at the state-level and similarly aggregate our estimated actionable RE integration potential from installing solar and wind near existing interconnections. This comparison allows us to determine the percentage of the required renewable capacity in each state that could be met by integrating solar and wind near existing fossil plant interconnections. To ensure consistency with regional planning needs, we adjust the actionable integration by capping it at the ReEDS-projected least-cost capacity portfolio for each state. If our integration potential exceeded the ReEDS estimate for a state, we limited it to the ReEDS requirement; if it was lower, we retained our original estimate.

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