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Editorial.

Domestic politics once again highlight the profound influence of political shifts on energy policy and the global energy transition. The recent U.S. federal election delivered a decisive victory to the Republican Party, granting it control of the White House and likely both chambers of Congress. It leaves the incoming administration under President Donald Trump positioned to advance its campaign priorities, which will again have significant ramifications for the U.S. energy sector. Among the stated goals of the incoming administration are plans to dramatically expand fossil fuel exploration and development while cutting government support for renewable energy, electric vehicles, and other investments in decarbonization. Past may serve as prologue, as the U.S. again withdraws from the Paris Agreement on climate change. While the full scale and details of these policy shifts will remain uncertain until further policy details are released, it also remains unclear to what extent the administration can counter fundamental market forces and technology trends, or how it will navigate potential resistance from within their own party from states that have seized economic opportunities from the energy transition and related policies such as the Inflation Reduction Act.

As this issue of our newsletter goes to print, the international community will be convening in Baku, Azerbaijan, for the 29th Session of the Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC). Delegates there are tasked with discussing a new collective quantified goal for climate finance and preparing the submission of new Nationally Determined Contributions (NDCs) for the coming year. Like every climate summit before it, these annual negotiations will once more highlight the persistent fault lines between countries and limits to decisive cooperative action. Just as in 2016, the outcome of the U.S. election will overshadow discussions within the corridors of the negotiating venue. Yet political shifts are by no means confined to North America: this year, more than half of the global population went to the polls, and election results everywhere suggest a global recalibration of priorities. Economic, social, and geopolitical concerns are gaining ground compared to climate policy, even as 2024 has once again shattered previous temperature records to become the hottest year ever documented.

Navigating the future of the energy system remains as complex and uncertain as ever. Yet amid these evolving challenges, one constant persists: the vital need for informed, objective research to guide the path ahead. Decisions made in the energy sector today do not only have to respond to the evolving policy landscape of the next four years, but also anticipate changes across future administrations. MIT CEEPR remains committed to harnessing its extensive networks across the political spectrum and connections with industry to provide robust, data-driven insights for improved decision making. The diversity and depth of research highlighted in this newsletter exemplify the methodological rigor and practical relevance of its work. As we witness shifts that may redefine energy policies and international cooperation for years to come, fact-based and non-partisan research acquires greater importance than ever. We invite you to explore the articles in this newsletter and join us in fostering a deeper understanding of the forces shaping domestic and global energy landscapes as we jointly define our energy future.

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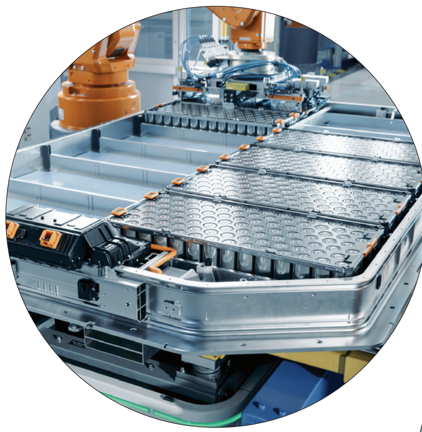

Research.

EU and US Approaches to Address Energy Poverty: Classifying and Evaluating Design Strategies

By: Peter Heller, Tim Schittekatte, and Carlos Batlle

As climate change continues to worsen and cause more extreme temperature fluctuations and weather events, access to sufficient energy services will be increasingly vital. Despite their essential role in the energy transition, low-income households are likely to experience the most significant impacts of these changes. Without the necessary financial support, they will unavoidably struggle to have access sufficient (affordable) energy to maintain adequate living conditions. The goal of this paper is to review how governments currently design strategies to reduce the overall number of households living in energy poverty in order to extract lessons on how to best deliver assistance.

Energy poverty, in the context of this paper, describes the inability of a household to adequately utilize sufficient amounts of electricity, heat, and other energy services due to financial constraints. It is driven by three main factors: sustained low incomes, high energy services costs, and poor dwelling energy efficiency. In the European Union (EU), approximately eight percent of households report being unable to keep their dwellings adequately warm. Nearly 10 percent of households in the United States (US) also keep their homes at unhealthy or unsafe temperatures, according to the 2020 Residential Energy Consumption Survey (RECS). In the same year, approximately 20 percent of households report having reduced or not purchased basic necessities in order to pay their energy bills.

In order to review and compare approaches to address energy poverty policy in both the EU and US contexts, we build a framework that includes four key categories of strategical decisions. These categories can be framed around four key questions:

- Assistance: What type of help should be employed?
- Targeting: Who should be targeted and by what criteria?
- Funding: Where are funds obtained to implement the policy?
- Governance: Who is responsible for implementation and oversight?

A summary of the four dimensions of energy poverty policy design discussed are presented Table 1.

A majority of the energy poverty policies implemented in the US and EU utilize direct assistance. These types of programs are important to provide immediate relief to households to ensure the lights stay on and that indoor temperatures remain healthy. Additionally, these policies are effective in the near term and can alleviate pressure on the

Assistance Strategy		**Direct Assistance**		**Indirect Assistance**
		Provided directly to the consumer; Proper calculation of the cost-reflective price, followed by a later application of discounts on such price		Provide support to act on causes of energy poverty, typically activities that lower energy consumption or act on costs to supply energy services
		Payment & Voucher	*Discount*	
		Direct transfer of money from the governing body for energy services costs	Act on the final price paid, with consumers paying a price lower than the cost-reflective amount; Can be distortive or non-distortive	
Targeting Strategy		**Targeted Assistance**		**Untargeted Assistance**
		Apply an explicit targeting strategy in order to properly identify the beneficiaries of the assistance; Governing body determines eligibility rules		Provide assistance to all consumers, or to a very broad part of them (e.g., all residential consumers), without trying to differentiate among their needs
		Application-Based	*Automatic*	
		Potential recipients must apply for benefits	Eligible recipients automatically receive benefits	
Funding Strategy	*Funding Source*	**State budget funding**	**Cross-subsidies**	**Unfunded Subsidies**
		Incorporation of subsidy scheme costs into state budget	Subsidies are covered through surcharges to other system users	Structural lack of financing, from either wrong estimations or explicit regulatory choices, eroding private capital
	Budget Calculation	**Top-down**	**Bottom-up**	
		Budget is pre-determined and amount of benefit is determined by number of participants	Amount of benefit is pre-determined and budget is determined by number of participants	
Governance Strategy	*Policy Creation*	**Centralized Governance**	**Localized Governance**	
		Assistance policy is created by central government and applies internationally/nationally	Assistance policy is created by local community and only serves those residents	
	Implementation & Oversight	**Central Administration**	**Regional / State Administration**	**Local Administration**
		Central governing body performs all duties	States or regional government responsible for implementation	Local governing body, NGO(s), or utility responsible for implementation

Table 1. Summary of Dimensions for Energy Poverty Policy Design.

governments to take action to help households. These policies work particularly well when there is an energy crisis and spikes in energy services costs are realized, but they can be seen as treating energy poverty as a temporary experience for households. In reality, there are many households that experience energy poverty consistently from year to year. This distinction between temporary and permanent energy poverty is important when considering the type of assistance strategy to employ. Indirect policies that address energy efficiency or provide access to distributed energy resources can serve to help address part of the underlying issues that pushes households into energy poverty (recall the three main drivers of energy poverty: sustained low incomes, high energy services costs, and poor dwelling energy efficiency). By working to fix the causes of energy poverty through indirect support policies, governments can begin to lift households out of energy poverty and reduce their reliance on direct support programs.

Regardless of the assistance strategy selected, the next step requires determination of which households will be eligible for the program. For energy poverty policies specifically, the criteria for targeting act as a quasi-definition for energy poverty; however, many targeted policies use only income data or social welfare status, which blurs the line between energy poverty and general poverty experiences. While households that experience energy poverty typically overlap with households that are living in poverty, as defined by the government, they are not always the same. There are households in which their income puts them above the poverty threshold, but their energy services costs either put them below the poverty line or they are forced to forgo the purchase of necessary goods to pay their energy bills. As a result, when thresholds are derived for governmental support, it is important to be cognizant of wrongful exclusion and wrongful inclusion in which numerical cutoffs force differentiation among individuals that should or should not be considered the same. Among the policies instituted in the EU to shield households from the energy crisis beginning in 2021, approximately 78% of all allocated and earmarked funding across member states was used for untargeted programs that acted on prices or supplemented incomes. This is purposeful wrongful inclusion as all households and businesses were affected greatly by the energy price shocks that occurred during the crisis.

In the long term, though, it is important to target these programs to households that need it most. If the only criteria to qualify for the program is energy burden, it is likely that some households experiencing energy poverty will be wrongfully excluded as they have an income above the threshold but high energy services costs or have purposefully reduced their consumption to unhealthy levels to lower their energy burden. On the other hand, some households could be wrongfully included if they have a moderate to high income but utilize large amounts of energy (e.g., for electric vehicle charging, private swimming pool heating, etc.) that push their energy burden to be above the threshold. In practice, though, obtaining data beyond income, energy burden, and demographic data can be challenging at the regional or national scale. As a result, many government programs must rely on a select few characteristics to qualify households that may lead to these inclusion and exclusion problems.

Beyond the eligibility criteria selection, we note a strong connection between the funding mechanism selected and the usage of an application versus automatic qualification. Policies that employ a top-down approach typically require applications from households to certify household eligibility. On the other hand, there is a clear parallel with the automatic qualification based on eligibility and the usage of the bottom-up approach. By estimating the budget based on the number of eligible households, the program is designed to provide benefit to all that qualify so automatic qualification works well. There are some cases of policies designed with the bottom-up approach that use an application system to certify eligibility; however, it is expected that all households that are able to prove eligibility will receive the benefit. In the top-down approach with applications, it is not guaranteed that all households will receive the benefit, as applications need to be reviewed and households selected for qualification to not erode the benefit to a non-useful amount. Figure 1 illustrates this phenomenon with data published by the US Department of Health and Human Services. Despite the increasing LIHEAP budget, the percent of income-eligible households receiving assistance is decreasing while the average amount of heating benefit remains constant.

The nominal value of heating benefit remains nearly constant; however, the percent of eligible households being helped is decreases over the period despite budget increases. This is a feature of the top-down approach that sets the budget first and then divides up the resources. This suggests that the number of federally eligible households is increasing at a faster rate than the budget for the program is increasing, and the top-down budget design is continuing to limit the number of eligible households that are receiving any assistance.

As a result of how the application process is designed in the US, there are only a limited number of eligible households that actually benefit from these programs. Despite the means testing approach successfully helping the households with the most need, with lowest income decided as the proxy, the LIHEAP and WAP programs in the US fail to help even more than one in four households that are eligible. Therefore, there is a decision to be made within the application design. If the application is solely to confirm household data that the governing body may not have readily available, it can still reach all of the eligible households. When decisions are made based on the application and automatic qualification is not made as a result of successfully submitting the application, families that deserve the assistance may not receive it. Additionally, an issue with any application-based program design is ensuring that all households have knowledge of the program and the resources to apply. Many families, often those who may need assistance the most, are unaware of a program's existence and lack the necessary information on how to enroll in them successfully. Lengthy applications and any required trips to government offices—only open during regular business hours—make these applications especially tough for low-income and rural families. When these programs rely on a household's knowledge of and access to program applications, they risk excluding households that require these benefits to maintain healthy, sustainable living conditions.

This analysis highlights the complex and multifaceted approaches taken by the US and EU to combat energy poverty. Through this review and classification of various policies and programs by assistance, targeting,

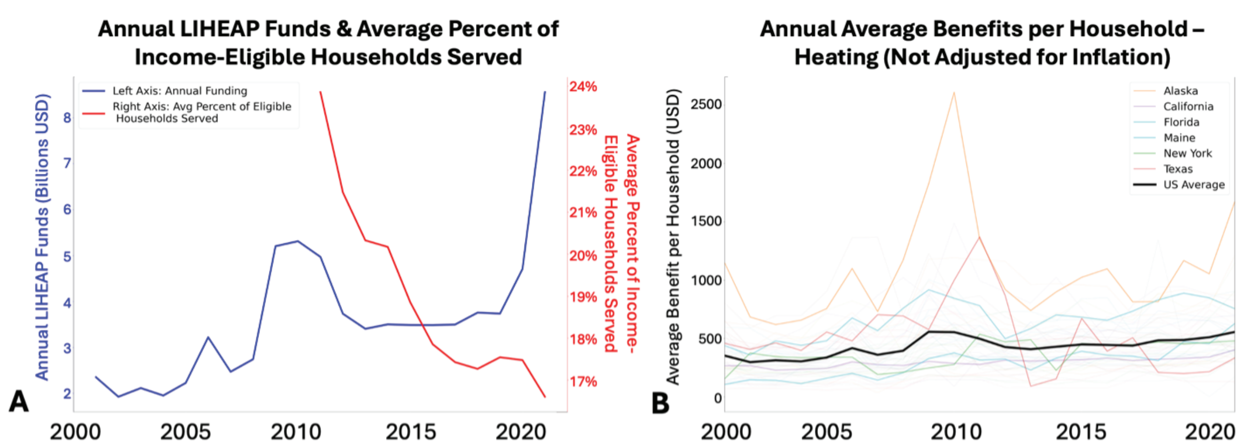

Figure 1. US LIHEAP Budget, Income-eligible Households Served, and Average Annual Heating Benefit.

funding, and governance strategies, we extract key challenges that governments face when designing them. While direct assistance programs provide crucial immediate relief, increasing emphasis on energy efficiency and affordability of distributed energy resources is needed to address the underlying causes of energy poverty. Balancing immediate support with long-term sustainable solutions is difficult both financially and politically; however, we have seen a shift towards this balance in recent years. The effectiveness of any of these strategies requires ongoing evaluation and adaption to ensure that they meet the evolving needs of the energy poor. Comprehensive data collection and access to utility data is necessary to improve the targeting of households and the ability of administering agencies to engage with them. Additionally, increased coordination among federal governments, local governments, and NGOs will combine the large-scale budgets and power of centralized governments with the local knowledge of lived experiences to better serve affected communities.

As climate change intensifies and wealth inequality increases, low-income households will face the greatest burdens of the energy transition despite being essential to the transition's success. Future policies should prioritize comprehensive strategies that integrate direct assistance with investments in sustainable energy infrastructure, fostering collaboration across sectors to innovate and implement solutions that not only alleviate energy poverty but also contribute to global environmental goals.

Peter Heller, Tim Schittekatte, and Carlos Batlle (2024), "EU and US Approaches to Address Energy Poverty: Classifying and Evaluating Design Strategies", CEEPR WP-2024-07, MIT, April 2024.

Research.

Choosing Climate Policies in a Second-best World with Incomplete Markets: Insights from a Bilevel Power System Model

By: Emil Dimanchev, Steven Gabriel, Stein-Erik Fleten, Filippo Pecci, and Magnus Korpås

The U.S. government relies on investment tax credits to increase private-sector investment in renewable energy. Other governments, as well as some U.S. states, have also implemented carbon prices to incentivize low-carbon investments. How should such policies be designed? How do they compare?

This paper explores how the answers to such questions depend on the ability of investors in electricity markets to sign long-term contracts with consumers. In liberalized power systems, markets for long-term contracts are generally illiquid, which is also known as the missing market problem. As a result, investors in new generation or storage capacity can be exposed to unhedged risk. What do such risks imply for policy makers seeking to cost-effectively incentivize low-carbon investments?

To explore policy choices, we introduce a general, game theoretic framework for modeling climate policies. The model explicitly represents the decision making of a government acting in anticipation of electricity market behavior. The advantage of this approach is that it generalizes the choice of optimal climate policy. It can be used to analyze the design of a variety of policies in view of diverse government objectives. The more traditional approach - modeling an energy system subject to an emissions constraint - is a special case in the context of our model.

Our experiments consider a government that aims to meet a given CO_2 target while maximizing social welfare. Risk-averse investors in new generation and storage capacity seek to maximize profit and consumers maximize consumer surplus. There is uncertainty about the overall electricity demand and the natural gas price. Importantly, investors and consumers lack the ability to engage in long-term electricity contracts. This missing market for risk drives a wedge between the optimal social welfare and the laissez-faire outcome from the electricity market. We refer to this as a "missing market" case, and compare it to a benchmark, "complete market" case, in which investors and consumers freely trade risk by engaging in long-term electricity contracts.

We compare two policies: investment tax credits for wind and solar and a carbon tax. In most of our experiments, we assume the government can use only one of these policy types. In each case, the government's aim is to choose the level of the policy—the level of the tax or of the renewable subsidies—that will incentivize producer and consumer decisions that keep emissions below the target while maximizing social welfare.

Our results suggest that the completeness of long-term markets may be an important determinant of optimal policy design. We observe that optimal renewable subsidies and carbon taxes are higher when long-term markets are missing than when they are complete. Missing risk markets skew the investment mix away from renewables and storage in particular. To compensate, governments must strengthen climate policies, whether in the form of subsidies or a carbon tax.

To inform the choice between renewable investment tax credits and carbon pricing, we consider which of the two policies is more cost-effective. Cost-effectiveness is here defined as achieving a given emissions target at the lowest risk-adjusted power system cost, which is our measure of social welfare. We expect the carbon tax to be more cost-effective when markets are complete, but not necessarily in the missing markets case. The theory of second best suggests the optimal policy in an efficient economy (where risk trading is complete) may not be optimal in an economy subject to a market inefficiency (such as incomplete long-term contracting).

The figure on the following page compares the cost-effectiveness of a carbon tax, wind and solar investment tax credits (labeled as ITC), and a policy mix, where the government can implement both policies at the same time.

The results suggest that the completeness of risk trading can influence the relative cost-effectiveness of subsidies and carbon pricing. When risk markets are complete (left panel in the figure), carbon pricing is always the most cost-effective policy instrument: it results in the lowest

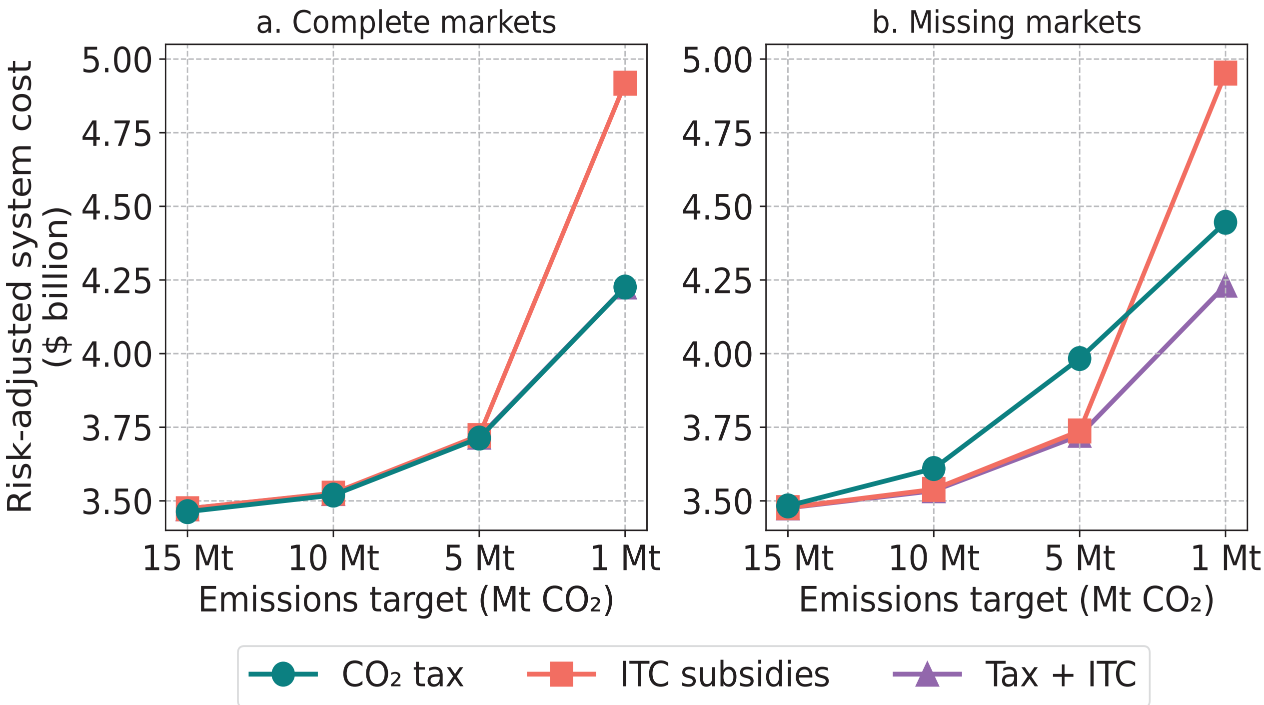

Figure 1. Renewable investment tax credit (ITC) subsidies can reduce emissions at a lower risk-adjusted system cost vis-à-vis carbon pricing.
Source: Dimanchev et al., (2024)

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risk-adjusted system cost. This is in line with our expectations. However, when long-term contracting is missing (right panel), we observe renewable subsidies to be more cost-effective than carbon pricing in some cases.

This finding reflects a rarely considered channel through which climate policy can benefit the economy. When risk trading is incomplete, electricity producers and consumers are exposed to unhedged risk. Renewable subsidies can reduce risk by shifting investment decisions toward renewables, which reduces reliance on uncertain gas generation costs. While carbon pricing incentivizes renewable deployment, it also results in a greater reliance on gas with CCS relative to renewable subsidies.

A policy mix combining subsidies and pricing consistently achieves the lowest possible system cost across our experiments (as shown by the purple line in the figure). Subsidies on their own are more expensive than carbon pricing at the deepest decarbonization level (as shown by the right-most markers in the right panel of the figure). In this case, their economic cost vis-à-vis the carbon tax outweighs their risk-related benefits. By implementing the two policies together, a government can leverage the advantages of each policy.

These exploratory experiments suggest that climate policy choices may have to consider the ability of decision makers to trade risk. The incompleteness of long-term contracting in liberalized power markets also motivates the design of hybrid power markets that incorporate long-term contracting mechanisms.

Emil Dimanchev, Steven Gabriel, Stein-Erik Fleten, Filippo Pecci, and Magnus Korpås (2024), "Choosing Climate Policies in a Second-best World with Incomplete Markets: Insights from a Bilevel Power System Model", CEEPR WP-2024-14, MIT, September 2024.

Hanna F. Scholta and Maximilian J. Blaschke (2024), "Shedding Light on Green Claims: The Impact of a Closer Temporal Alignment of Supply and Demand in Voluntary Green Electricity Markets", CEEPR WP-2024-08, MIT, June 2024. For references cited in this story, full bibliographical information can be found in the Working Paper.

Research.

Shedding Light on Green Claims: The Impact of a Closer Temporal Alignment of Supply and Demand in Voluntary Green Electricity Markets

By: Hanna F. Scholta and Maximilian J. Blaschke

With the intensifying global focus on fighting climate change, more consumers are turning to green energy, often verified through energy attribute certificates (EACs). These certificates assure consumers that their energy consumption is backed by renewable sources. However, the predominant mechanism, which matches supply and demand only on an annual volumetric basis, has been criticized for lacking transparency (Brander et al., 2018; Hast et al., 2015; Mulder & Zomer, 2016; Nordenstam et al., 2018; Winther & Ericson, 2013) and for its inefficacy in stimulating investments in renewable energy infrastructure (Bird et al., 2002; Gillenwater et al., 2014; Hamburger, 2019; Herbes et al., 2020; Markard & Truffer, 2006). Recent studies call for a revision of current accounting practices for environmental claims. Bjørn et al. (2022) express concerns about the inflated effectiveness of mitigation efforts due to the widespread use of EACs. Similarly, de Chalendar and Benson (2019) advocate for corporate carbon accounting to reflect the benefits of different types of renewable energy, dependent on the local grid mix at a certain time of day. Xu et al. (2024) suggest that aligning green electricity generation and corporate consumption geographically and temporally, specifically through hourly matching, enhances CO_2 emissions reduction per MWh. However, this comes with the drawback of higher system costs.

Our paper investigates the robustness of green electricity claims when subject to shorter measurement intervals and, hence, stricter temporal alignment between green electricity supply and demand. Using real-world European EAC data from 2016 to 2021 alongside European data on electricity demand and renewable supply, we investigate the impact of adjusting the temporal granularity of matching periods – from annual to more frequent intervals such as quarterly, monthly, weekly, daily, and hourly. By considering the implications for renewable energy installations and flexibility measures, we formulate policy recommendations to optimize the effects of these green claims.

We approximate annual green electricity supply and demand using the issuance and cancellation of EACs under annual matching. We interpolate hourly EAC issuance and cancellation based on renewable energy generation and consumption data and test the system for sufficient coverage of green electricity at various hypothetical matching

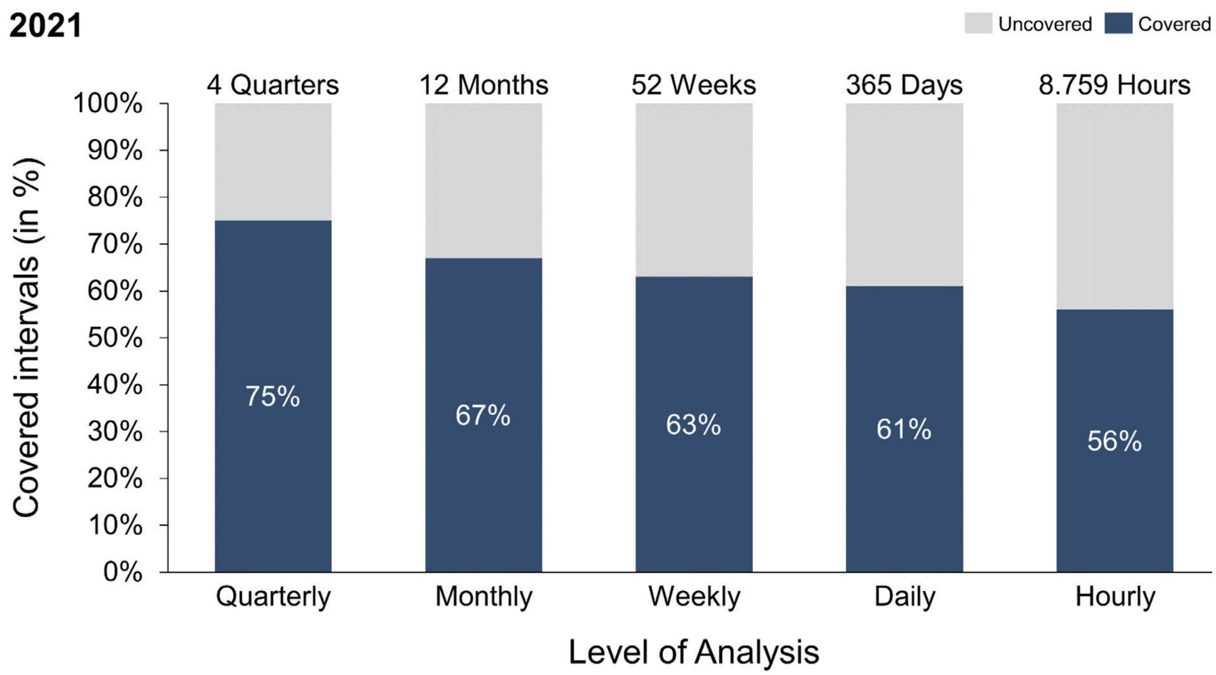

Figure 1. Share of intervals where green electricity demand was covered with green electricity supply in 2021, depending on the imposed matching period (in % of all intervals at the respective level of analysis).

periods, namely quarterly, monthly, weekly, daily, and hourly.

For more granular matching periods, we observe severe discrepancies between green electricity demand and supply, as illustrated in Figure 1 for 2021. The prevailing annual matching conceals significant shortfalls in green electricity supply, especially during periods of high demand. More granular matching periods expose these gaps. Our simulation with quarterly matching shows deficits in supply during the first and fourth quarters, times typically associated with lower renewable energy generation due to seasonal variations in solar and wind energy production. Transitioning to quarterly matching could more accurately reflect seasonal variances in supply and demand, potentially increasing the market value of GOs during periods of shortage. These price differences in GOs may then incentivize further investments in renewables and flexibility measures, e.g. long-duration storage.

We find total shortages in uncovered intervals relative to the yearly green electricity demand to peak at the imposition of hourly matching. At this matching granularity, two major trends stand out: Firstly, there has been an overall increase in the share of intervals with insufficient coverage in recent years. Secondly, the night hours exhibit a higher number of shortages than the day hours, and the disparity has grown more pronounced over the years. Due to the increasing day-night disparity, even quarterly matching may eventually fail to provide adequate transparency and incentives. The introduction of hourly matching, however, could elevate the value of EACs issued during nighttime or early morning hours. These relative price increases may, for instance, trigger increased deployment of west or east-angled photovoltaic units for higher production outside the peak hours. Moreover, on the demand side, hourly matching could support shifting consumption from high-priced EAC hours to periods with abundant green electricity supply (see Blaschke, 2022).

Given the high system costs associated with hourly matching (see Xu et al., 2014), we initially recommend moving to quarterly matching. Nonetheless, our findings stress the long-term necessity of hourly matching when aiming for effective green claims based on EACs. To incentivize not only the expansion of appropriate renewable energy capacities and demand-side measures but also the enhancement of flexibility measures, we recommend integrating energy storage as a dynamic component within the green electricity market—permitting storage systems to both consume and issue certificates.

Our research underscores significant issues with the current structure of EAC markets and suggests that moving to more granular matching could alleviate those. Implementing our recommendations could foster more robust growth in renewable energy capacities and flexibility measures. Hence, our study serves as a call to action for policymakers, market operators, and stakeholders within the renewable energy sector to critically reevaluate and reform green electricity certification practices and regulations. By doing so, they can ensure that EACs fulfill their potential as catalysts for transitioning to a sustainable and resilient energy system.

Research.

Optimizing Mineral Extraction and Processing for the Energy Transition: Evaluating Efficiency in Single versus Joint Production

By: Mahelet G. Fikru and Ilenia G. Romani

Efficient extraction and processing of ores into metals are fundamental to several clean energy transition technologies. Metals such as copper, nickel, indium, platinum, and cobalt are vital for wind turbines, solar panels, fuel cells, energy storage systems, and electric vehicles. However, the production of certain critical metals faces challenges such as high processing costs and supply chain constraints. This research investigates the economic viability and cost dynamics of single versus joint metal production, aiming to provide insights that can optimize mineral extraction and processing for the energy transition.

To analyze the cost dynamics of single and joint metal production, we develop a theoretical model grounded in optimization theories. The model characterizes the average cost of processing ore for two types of firms: single metal producers and joint metal producers. Single metal producers process ore to extract one metal, while joint metal producers extract two or more metals from the same ore.

The model incorporates several parameters, including:

- Per unit mining and processing costs
- Taxes per unit of ore
- Total factor productivity
- Metal demand
- Volume of ore processed

We use constrained optimization to derive conditions under which joint metal production can offer cost savings compared to single metal production. The analysis includes deriving conditional ore demand and characterizing optimized average costs for both types of firms. The model highlights the role of relative output elasticities, which measure how output changes with respect to input changes, in determining production efficiency and average costs. Higher relative output elasticity can lead to lower average costs, particularly in joint metal production.

In addition, the theoretical models are complemented with an empirical analysis based on data from 427 mining projects worldwide. This dataset includes information on the average cost of processing ore, the volume of ore processed, and the types of metals produced. Among these projects, 62 are joint metal producers, producing combinations such as copper-cobalt (Cu-Co), cobalt-nickel (Co-Ni), and copper-nickel (Cu-Ni). The remaining 365 sites are single metal producers.

By comparing site-level average costs across different countries, metal types, and producer types, we interpret patterns in the data using the solutions from the constrained optimization model. The empirical analysis reveals that joint metal producers often face higher average costs compared to single metal producers. However, under certain conditions, joint production can achieve cost efficiencies.

We find that several factors influence the average costs of processing ores:

- Per Unit Costs: Higher per unit mining and processing costs increase the average cost for both single and joint metal producers.
- Taxes: Taxes per unit of ore significantly impact cost dynamics, especially for single metal producers.
- Total Factor Productivity: Improvements in total factor productivity can reduce average costs, benefiting joint metal producers more due to their complex operations.
- Metal Demand: Fluctuations in metal demand affect pricing and, consequently, cost structures. High demand can drive up prices, impacting cost efficiency.
- Volume of Ore Processed: Larger volumes of ore processed can lead to economies of scale, reducing average costs for both types of producers.

The theoretical and empirical analyses show that single metal producers generally have lower average costs compared to joint metal producers. This is attributed to the simpler processing requirements and established technologies for base metals like copper. However, joint metal production can achieve cost savings when the relative output elasticity of the ore is high. In such cases, the efficiency gains from processing multiple metals can offset the higher initial costs.

In fact, joint metal producers experience more nuanced cost variations tied to changing per unit cost parameters, metal demand, ore volume processed, and total factor productivity. The model highlights how higher relative output elasticity of ore can lead to lower average costs, making joint production economically viable under such specific conditions.

These findings have significant implications for production decisions and supply chain management. Mining and metallurgical firms can use these insights to decide whether and when to adopt single versus joint production strategies based on the relative output elasticities of the ores for different metals. Understanding factors that influence average costs can help producers optimize their cost structures.

In terms of policy implications, industry stakeholders might employ several strategies to address the higher average costs faced by joint metal producers. From investing in Research and Development (R&D) for innovative mining and metal refining technologies, to information sharing within industry associations, using them as platforms for sharing best practices and knowledge, driving improvements in cost efficiency. Finally, government support could play a crucial role, with policies and programs supporting innovation and cost efficiency in mining technology, to enhance the competitiveness and sustainability of the sector.

Mahelet G. Fikru and Ilenia G. Romani (2024), "Optimizing Mineral Extraction and Processing for the Energy Transition: Evaluating Efficiency in Single versus Joint Production", CEEPR WP-2024-09, MIT, July 2024.

For references cited in this story, full bibliographical information can be found in the Working Paper listed above.

Commentary.

A Roadmap for Advanced Transmission Technology Adoption

By: Brian Deese, Rob Gramlich, and Anna Pasnau

U.S. electricity deployment is falling behind the pace necessary to meet projected demand growth—posing risks for the United States' ability to meet its clean energy deployment goals and raising costs for ratepayers. In recent months, this challenge has become more urgent as the gradual shift of electrification has collided with a near-term increase in electricity demand brought on by the electrification of buildings and transportation, renewed domestic manufacturing, cryptocurrency mining, and data centers.

Increased use of advanced transmission technologies (ATTs) can play a major role in meeting this demand growth quickly and cost-effectively. However, electricity market structures—which disincentivize investment in innovation—are impeding progress towards modernizing the electric grid. Policies that overcome these obstacles to incentivize ATT adoption can expand grid capacity, lower costs for ratepayers, and help the U.S. meet its energy deployment and energy security goals. This paper lays out a five-part framework for unlocking the potential of ATTs.

I. The Need for Advanced Transmission Technologies

The recent increase in demand for electricity after two decades of flat, low demand growth has generated alarming assessments from a range of utilities, regulators, and industry analysts.

We are already seeing a surge of investment in clean energy to meet this demand, with over $79 billion in investments in clean energy and industry in 2023. However, system bottlenecks are preventing this investment from translating into increased electricity generation resources. Over the course of 2023, the backlog of generator and storage capacity actively seeking interconnection to the electric grid increased by 27 percent—by December 2023, nearly 2,600 GW of generator and storage capacity were in the "queue," 95 percent of which was solar, storage, and wind.

Beyond connection to the grid, the U.S. also lacks the necessary transmission infrastructure to deliver more power. The Department of Energy (DOE) has estimated that by 2035, transmission infrastructure will need to grow by 57 percent. Despite this, high-voltage transmission construction has slowed from an average of 1,700 miles built per year between 2010 and 2014 to only 55 miles built in 2023.

Unlocking these system constraints is crucial to meeting the country's growing electricity demand without undermining our clean energy goals or shifting significant new costs to consumers. Grid capacity constraints are already driving up costs for ratepayers; in 2022, congestion costs rose by more than 50 percent to $21 billion.

However, fixing our grid challenges is complex and multifaceted. It will require reforming the process by which interconnection requests are evaluated and approved. It will also require building new long distance transmission lines to move electricity more efficiently from the location where it is generated to where it is needed.

In the near-term, perhaps the most powerful opportunity for progress involves increasing the capacity of the electricity grid without building entirely new lines or systems. With so-called advanced transmission technologies (ATTs), we can expand transmission capacity quickly by improving utilization of existing grid infrastructure. According to a recent DOE report, wider implementation of these solutions could meet our expected 10-year peak demand growth if deployed rapidly. The technologies are particularly useful in the context of widespread permitting and siting constraints, which are especially challenging for high-voltage interstate transmission—they avoid such obstacles by using existing right of ways.

ATTs are also cost-effective. One estimate looking at Illinois, Indiana, Ohio, Pennsylvania, and Virginia found that adoption of three ATTs would cost about $100 million and yield about $1 billion in annual production cost savings. Another report found that GETs (a subset of ATTs, as described in the below box) could deliver $5 billion in yearly energy production cost savings, with upfront investment paid back in just 6 months. In effect, supporting their adoption may be the closest energy policy analog we have today to finding a $20 bill on the table. The potential of these technologies is well-understood. Advanced conductors have been in the market since the early 2000s, topology optimization has been studied since the early 1980s, and power flow controllers were introduced in the 1970s. Moreover, in some places their use is widespread. Countries including Belgium, the Netherlands, Italy, India, and China have pursued large-scale reconductoring projects to quickly expand transmission capacity. In 2021, the U.K. transmission operator National Grid deployed 48 advanced power flow control devices across its grid, unlocking 1.5 GW of electric capacity and saving the operator an estimated $500 million over seven years. And in the United States, AES deployed dynamic line rating (DLR) sensors across five transmission lines in Indiana and Ohio—the upgrade took only 9 months, cost $45,000 per mile, and increased capacity by more than 50 percent. Another DLR upgrade in Syracuse, New York is estimated to increase capacity by 20-30 percent across four transmission lines.

II. Obstacles to ATT Adoption

The incentives for transmission providers, information provided to regulators, and features of electricity markets slow the adoption of these technologies in the United States.

First, the profit structure of electricity markets fails to incentivize transmission providers to adopt many forms of ATTs, despite their benefits to ratepayers and capacity. Under the current electricity industry regulatory structure, utilities earn profits from capital

WHAT ARE ADVANCED TRANSMISSION TECHNOLOGIES?

Advanced transmission technologies refer to a set of technologies that can increase physical line capacity. This box summarizes a few of the most widely used technologies.

Dynamic line ratings (DLRs): DLRs increase capacity by an average of 10-30 percent, take less than three to six months to deploy, and cost less than 5 percent of the price of building new transmission. As air temperatures rise, the carrying capacity of electric power cables decreases. Accordingly, grid transmission lines are given static line ratings that determine the amount of power that can be transmitted on the line, with conservative assumptions for weather conditions (high temperatures, full sun exposure, little wind cooling) at all times. When the weather is better than these conditions, transmission lines can safely transmit additional power; when the weather is worse, it risks damage to the line. DLRs involve the real-time calculation of a transmission line's thermal capacity based on local conditions, typically using a device installed on or near the line to collect this information. In most conditions, DLRs allow operators to increase the amount of power the line can safely carry. Occasionally in extremely bad weather, they report reduced power transfer capacity on the line, thereby protecting the system's reliability.

Advanced power flow control devices (APFCs): APFCs increase capacity by 10-25 percent or more and take less than fifteen months to deploy. These power-electronics-based devices enable the dynamic adjustment of network power flow by changing line reactance. This can enable the redistribution of power from lines that are overcapacity to lines with available capacity, significantly increasing firm system capacity, reducing congestion, and accelerating grid modernization.

Topology optimization: Topology optimization can increase capacity by about 5-50 percent and takes less than three to six months to deploy. Topology optimization software models the grid's network and conditions to identify and address congestion by switching transmission branch elements, including transmission lines and transformers, using pre-existing high voltage circuit breakers to efficiently distribute power flow across the grid.

High-performance conductors (HPCs): HPCs generally double capacity (but can increase capacity by as much as 10 times in some cases) and reduce transmission line losses by roughly 30 percent. They can take one to three years to deploy (when reconductoring existing lines). HPCs are conductors made with carbon, composite cores, or other advanced materials like high-temperature superconducting tape instead of steel. Transmission providers can replace the traditional conductors on existing lines ("reconductoring") or use HPCs in the construction of new transmission lines. While HPCs can be almost three times as expensive as conventional conductors, reconductoring costs less than half the price of building new transmission lines.

Many of the leading companies manufacturing these technologies are headquartered in the United States, including LineVision, Lindsey Systems, and Atecnum (DLR); Smart Wires (DLR and APFC); NewGrid (topology optimization); CTC Global and TS Conductor (advanced conductors); VEIR (superconductors); and MetOx (superconducting tape).

Dynamic line ratings, advanced power flow control devices, and transmission switching are all classified as "grid-enhancing technologies" (GETs), a subcategory of ATTs that enable the optimization and control of a dynamic grid. The underlying obstacles to—and solutions for—adoption, described in detail below, vary slightly for GETs as opposed to high-performance conductors.

expenditures, meaning that they are incentivized to make more costly capital investments (e.g. building a new power plant) over changing their operating expenses or lowering and smoothing demand for electricity—even when those capital expenditures ultimately increase costs for consumers. This "capex bias," which has become an accepted and well-known feature of cost-of-service regulation for over 50 years, ultimately means that transmission providers lack a positive incentive to use GETs or can be disincentivized from using GETs. Because GETs can obviate the need for more costly construction of new transmission lines, thereby reducing utility capital expenditures, they can lower utilities' profits. Even high-performance conductors, which are more expensive than regular conductors, can lower profits when they are installed in lieu of building new transmission—reconductoring transmission lines costs less than half as much as building new transmission.

Second, current regulatory practices limit ATT adoption. Regulators are tasked with preventing utilities from taking advantage of capex bias and with ensuring utilities make investments that are in the best interest of their consumers. However, both transmission providers and regulators can struggle to identify the best way to expand capacity against a backdrop of multiple options, and for some technologies, they need new modeling practices to assess benefits. Transmission providers and their regulators have historically focused their cost-benefit analyses on a narrow set of risks and thus are slow to scale innovations, preferring the status quo. The possibility of regulators blocking utilities' proposals may discourage utilities from including ATTs in their plans.

In the case of high-performance conductors, specifically, even as the "opportunity cost" of installing high-performance conductors (instead of building new transmission) may disincentivize transmission providers from using them, high-performance conductors can also be blocked by regulators for being more expensive than regular conductors. Regulators have a mandate to monitor and prevent so-called "gold-plating" (the practice of excessive spending on capital expenditures in order to increase utilities' profits). They may mistakenly see high-performance conductors as gold-plating due to their initial high cost because they lack the necessary information to see the savings enabled by high-performance conductors.

Third, in some cases, transmission investment of all kinds (including in ATTs) may be limited by a chicken-and-egg problem, where transmission developments are not economical until they connect to generation facilities, but generation facilities cannot be built until transmission is in place.

III. Policy Solutions

Overcoming these barriers to adoption requires modernizing the practices of and incentives facing transmission providers. Some states are taking action: in May 2024, Minnesota's state legislature passed a law requiring the consideration of ATTs in transmission planning. In 2023, Montana's state legislature unanimously passed a law allowing utilities that use high-performance conductors to receive additional profits (legislators were encouraged by CTC Global, a leading manufacturer of high-performance conductors). Nine states have implemented performance-based regulation to align utility incentives with key performance metrics. And on a national level, the Federal Energy Regulatory Commission's (FERC) Order 1920, finalized in May 2024, requires transmission providers to consider the use of ATTs.

These steps are positive but not sufficient to drive more rapid widespread adoption of ATTs across our electricity system. This paper lays out reforms in five categories that can drive adoption of ATTs.

1. Requiring transmission providers to use ATTs in certain contexts;

2. Requiring transmission providers and regulators to conduct robust analyses of the value of ATTs for their current footprint;

3. Creating financial incentives for transmission providers to adopt ATTs where they can provide significant net benefits;

4. Requiring transmission providers to release additional data on the grid and building digital tools to inform ATTs adoption;

5. Requiring transmission providers to release data to a third-party entity that takes on the responsibility of planning ATT adoption.

Recommendation #1: Require transmission providers to adopt ATTs in certain contexts.

There are some circumstances in which ATTs have no major downside ("no regrets" upgrades), such as in the deployment of DLRs on congested lines. In these cases, requiring the use of efficient tech is the most effective way to drive rapid adoption.

FERC should require DLRs – which are a cost-effective way to increase the capacity and resilience of grids—for highly congested lines. This would increase capacity for certain lines, lowering congestion costs for ratepayers. Installing DLRs costs roughly one-tenth as much as reconductoring with high-performance conductors (one-twentieth the price of building new transmission) and can increase capacity by 10-30 percent. Accordingly, PJM Interconnection, the country's largest grid operator, has proposed that thermally limited lines with high historical ($2 million or more per year on average) and projected ($1 million or more per year on average) congestion should be required to deploy DLRs. Very few lines—likely less than two dozen—would meet this threshold, but even a high threshold would be a good start to address some extremely congested lines. FERC currently has an open DLR Advance Notice of Proposed Rulemaking (ANOPR), which proposes requiring DLRs on certain lines based on ambient weather conditions, solar conditions, wind speed, and congestion. The ANOPR includes certain fairly conservative provisions designed to slow implementation, such as a limit on the number of lines to which transmission providers can be required to add DLRs (a proposed 0.25 percent of the transmission providers' lines per year—even if additional lines meet the requisite congestion and weather condition thresholds).

Additionally, **DOE should adopt a national conductor efficiency standard.** This would ensure that transmission providers install more efficient transmission lines, which can reduce line electricity losses by 30 percent. Between 2018 and 2022, annual electricity transmission and distribution losses averaged about 5 percent of all electricity transmitted and distributed in the United States. Approximately one third of those losses occur in the transmission of electricity. While increased capacity may not always be necessary, increased efficiency has no downsides. Congress's 2023 appropriations included funding for a conductor efficiency study regarding the environmental, economic, and clean energy deployment benefits of establishing an energy conservation standard for overhead electricity conductors. When that study is released, DOE should use its results to support an efficiency standard for conductors, which would require transmission providers to reconductor inefficient transmission lines.

DOE has the authority to promulgate efficiency standards for industrial equipment, but Congress could further clarify DOE's authority to promulgate standards for transmission conductors, as it did in 1992 for distribution transformers. While the design of the standard should be shaped by DOE's findings from the conductor efficiency study, the efficiency standard could operate similarly to distribution transformer efficiency standards, which are updated every six years and provide a compliance timeframe of five years.

Recommendation #2: Require transmission providers and regulators to conduct robust analyses of the value of ATTs for their electric grid.

ATT adoption requires thorough analysis of where the technologies have benefits for grid capacity that exceed their costs. Today, regulators and transmission providers are often not transparent about how they evaluate the use of ATTs. Because transmission providers are less accustomed to ATTs and may have incomplete information about their benefits and disadvantages, they may be reluctant to consider them in planning. Similarly, if transmission providers suspect regulators will reject the use of ATTs, they are likely to be conservative about proposing ATTs.

FERC Order No. 1920, finalized in May 2024 has the potential to help address these problems by requiring the consideration of ATTs (DLRs, advanced power flow control devices, advanced conductors, and transmission switching) in long-term regional transmission planning, building new facilities, and upgrading existing facilities. However, the impact of the order will depend on how in-depth transmission providers' consideration actually is. Order 1920 currently lacks the necessary specificity—or enforcement mechanisms—to ensure that transmission providers actually adopt ATTs where they are beneficial. An effort to ensure transmission providers meaningfully include ATTs in their planning in the initial implementation phase of this order will be essential to ensuring that consideration is more than just cursory box-checking.

Moreover, some aspects of Order 1920 currently limit its efficacy with respect to ATTs adoption. The order requires that transmission providers engage in proactive, forward-looking (at least 20 years into the future) regional planning at least every five years. This timing is out of sync with the timing of ATTs deployment, as ATTs can be deployed in months or a few years. The need for increased capacity could arise and be met by ATTs all within the five years between transmission plans.

In their implementation of these orders, regions should plan to put a good faith effort into evaluating ATTs—and regulators to effectively enforcing compliance with the order. This would help the order produce its intended effect by encouraging regions to comprehensively evaluate ATTs. In response to Order 1920, each region must file a compliance plan within 12 months for FERC to adjudicate. In the adjudication process, FERC has discretion over how strictly to enforce its provisions, but once the commission approves compliance plans, industry will take the lead on implementing the order. The opportunity for ensuring maximum impact of Order 1920, therefore, is during the compliance plan process.

Regions should include in their compliance plans detailed descriptions of how they will make good faith efforts at evaluating ATTs—including describing the data and assumptions they will use. They should also volunteer to conduct planning on a more regular cadence than every five years, perhaps every two years or similar. And in its adjudication process, FERC should enforce compliance with the intentions of the order by holding these plans to a high standard. The attention of third-party watchdog organizations on this compliance plan process is critical to ensuring all regions engage seriously with the order.

To supplement FERC Order 1920, states should adopt legislation that requires transmission providers to comprehensively assess the potential use of ATTs in their transmission planning, since both states and FERC have jurisdiction over transmission. This would act as a backstop for FERC Order 1920 and further encourage transmission providers to seriously consider ATTs. These requirements were recently enacted in Minnesota's HF 5247, which adds GETs to the state's transmission planning process and requires utilities owning more than 750 miles of transmission lines to evaluate GETs on highly congested lines. Similarly, this year Virginia passed a law requiring utilities to consider GETs in their long-term planning process, although the law limited this requirement to planning for distribution lines, making it less effective. Both laws target existing state-jurisdictional issues and processes, which makes them more legally durable, as they act at the fuzzy intersection of state and federal oversight of the electricity system. It may be helpful for DOE to put forth a set of model regulations or legislation—or a series of best practices—that states could use to develop these requirements.

DOE should provide funding to regional state committees for staff or consulting expertise to identify opportunities for ATTs. This would allow regional state committees to serve as a check on transmission plans and to propose alternatives where necessary. Regional state committees—such as the Organization of MISO States (OMS), the Organization of PJM States Inc (OPSI), or the New England States Committee on Electricity (NESCOE)—were formed by states in part to coordinate and provide policy input to RTOs on issues including transmission design. They could serve as a second perspective on opportunities for ATTs adoption and could coordinate recommendations within regions. NESCOE has already called on New England transmission owners to develop an Asset Condition Guidance Document that provides transparency into the process and criteria by which transmission owners identify transmission needs and determine how to meet those needs (including with advanced transmission technologies).

Recommendation #3: Creating financial incentives for transmission providers to adopt ATTs where they can provide high net benefits.

Even if utilities and regulators conduct analyses on where ATTs can lower costs and expand capacity, the industry structure still disincentivizes ATT adoption. Targeted policy actions can help increase the incentives for adopting ATTs to offset these obstacles. Ideally, insofar as they meet the same capacity need, developers should be indifferent on a profitability basis between ATT projects and a new transmission line build. While perfect parity may be difficult to achieve in practice, greater incentives for ATT use would increase adoption.

FERC should adopt a "shared savings" incentive nationally. This would allow utilities that use GETs to earn a profit for saving ratepayers money, shifting incentives towards performance and not just investment, and could have a significant effect on GETs adoption. On the whole, it could lead to billions in consumer savings each year. A shared savings proposal, developed by the WATT Coalition and Advanced Energy United (and based on similar incentives in the UK and Australia), was vetted by FERC in 2021. Under the proposal, the planning authority would evaluate projects using standard cost and benefits calculations, which usually include production cost and capacity cost savings. For projects that use GETs, cost under $25 million, and have a benefit-cost ratio of at least 4:1, the utility would receive a portion of the net savings (taken out of the savings to ratepayers). The WATT Coalition has proposed that smaller projects (projects costing less than $2.5 million) receive a standard percentage of the benefits, perhaps 25 percent. Larger projects could undergo a competitive proposal process in which project developers propose a share of savings and the planning authority awards the project to the developer who proposed the lowest cost option overall. Project developers would only be eligible for shared savings for the first three years of the project's operation unless those projects continued to show a cost-benefit ratio higher than 4:1. This incentive was recently included in the Advancing GETs Act proposed by Senator Peter Welch.

Where possible, **state legislatures should authorize an additional return on equity for projects that use cost-effective ATTs.** This would increase the profits utilities earn when they use ATTs, suppressing the effects of capex bias. While an adder may have limited benefits for

GETs adoption on existing lines (which have tiny upfront capital investments and would be better supported by a shared savings incentive), it would be helpful for high-performance conductors (which are not supported by the WATT Coalition's shared savings incentive). This has already been enacted in Montana, where HB 729 allows the state's public service commission to develop cost-effectiveness criteria for advanced conductor projects, ensuring that utilities and regulators know how proposed advanced conductor projects will be evaluated, and allows the state's regulator to determine an appropriate return-on-investment adder (up to 2 percent) for projects that use advanced conductors, financially incentivizing utilities to install advanced conductors.

DOE should expand its Grid Deployment Office (GDO) to facilitate financing for ATTs. This would provide capital to help overcome the chicken-and-egg challenge. Joshua Macey and Rob Gramlich have advocated for the GDO to take an enhanced role in providing financial assurances to developers who build lines in new transmission corridors. DOE is already authorized to borrow up to $2.5 billion under the Transmission Facilitation Program and $2 billion under the Transmission Facility Financing Program. GDO could help make better use of these funds by purchasing up to half of planned line capacity, providing loans directly, and participating in public-private partnerships within designated National Interest Electric Transmission Corridors. GDO could then recover those costs from utilities through direct cost allocation, enabling them to reuse the funding.

Recommendation #4: Build digital tools that inform ATTs adoption.

In many cases, transmission providers lack detailed, accurate information about expected demand, planned transmission, and the potential advantages or disadvantages of ATTs. At the same time, regulators, consumer advocates, environmental policy groups, and other stakeholders lack the necessary information to hold providers accountable when they fail to act in the best interest of their ratepayers. Even when that information is available, it is often siloed, making it difficult to grasp a full picture of the U.S. electric grid, to identify high-priority needs, and to promote connectivity across regions.

FERC should require transmission providers to share additional information publicly. This would allow third-party groups to evaluate utilities' adoption of ATTs and to hold utilities accountable when they fail to make the necessary investments in transmission. The WATT Coalition has recommended that FERC require utilities (where permissible under Critical Energy/Electric Infrastructure Information Regulations) to release information about transmission capacity and planned upgrades and expansions; a list of transmission constraints that caused, or are projected to cause, $500,000 of yearly congestion— along with the cause of that constraint; and a list of GETs and other non-wires alternatives that transmission providers might use to resolve constraints and conditions under which each would be applied. Among grid operators, there is already some understanding of the need for increased data sharing; PJM has said it would be willing to share with FERC historical and projected congestion levels on an annual basis. And FERC is already moving in that direction; its DLR ANOPR proposes additional reporting requirements for transmission providers in non-RTO regions, including requiring providers to maintain a database with information on instances of congestion and the limiting elements causing it.

Researchers, likely at a national lab, should develop a "digital twin" of the current transmission system that can support evaluation of the impact of various ATTs on grid capacity. The digital twin model would allow more accurate analysis of where ATTs may be advantageous and could be used by transmission providers to inform their analyses, by regulators to evaluate providers' plans, or by environmental groups to enforce smart transmission expansion. This modeling exercise has been attempted in the past and failed due to a lack of data sharing—successful development would necessitate transmission providers sharing detailed data (on electricity demand and supply, line efficiency, use of ATTs, age, and quality of equipment) to facilitate more advanced modeling of transmission needs. To ensure compliance with CEII Regulations, the model and relevant data would likely need to be maintained by a national lab.

"Hyperscaler" organizations that are operating large-scale data centers and driving up electricity demand could support the capacity of national labs to develop these modeling capabilities. Some hyperscalers are having difficulty meeting their own climate goals; financial or technical support for grid modeling could help them meet their electricity demand with clean energy, thereby lowering their emissions.

Recommendation #5: Shift the responsibility of planning ATTs to a third party.

While our proposed reforms could substantially increase ATTs adoption, they do not eliminate the underlying challenges that limit adoption: namely the industry structure where transmission providers do not profit from the adoption of ATTs and thus are disincentivized to adopt them, and where regulators are limited in their ability to pressure-test providers' decisions by a lack of resources and data. In the context of FERC Order 1920, while grid operators are now required to consider grid-enhancing technologies, regulators will have few ways of determining whether adequate consideration has taken place. At the same time, without systemic change to the transmission planning process or utility incentives, transmission providers will continue to adopt ATTs at suboptimal rates—with negative consequences for their ratepayers and for their ability to build out sufficient capacity to meet our climate goals.

Our first four proposed reforms could significantly increase ATTs adoption and would be considerably better than failing to act altogether. However, truly addressing the obstacles to adoption would require a more transformative reform, namely shifting the responsibility of planning ATTs away from transmission providers altogether. FERC could require transmission providers to release relevant data on an annual basis to NREL or a different uninterested nonprofit entity with the capacity to house and process sensitive data securely. These data would include information about transmission capacity and planned upgrades and expansions, current ATTs use, age and condition of equipment, electricity demand, and line congestion. CEII would be respected with appropriate constraints in place to make sure that all data are secure and there is no sharing of sensitive information.

The third party would develop a plan for each grid operators' optimal adoption of ATTs based on these data and publish it on a regular basis (akin to the 5-year FERC Order 1920 cycle—transmission providers would still be able to adopt additional ATTs in the intervening years). The utility would be required to either take the third party's recommendations or to provide an explanation for why the proposed approach is inappropriate and offer a counterproposal.

Transmission providers may be reluctant to release their data or to delegate planning responsibilities to another organization. Without substantial data sharing, no third party would have the necessary information to evaluate opportunities for ATT adoption. Despite this, the recommendation could lead to significant benefits by more fully addressing the structural factors that disincentivize ATT adoption. Tasking one entity with coordinating ATT adoption across the entire grid could also promote complementary ATT adoption and eliminate redundancies.

Conclusion

The United States has reached a pivotal moment for its electric grid. After decades of low growth in electricity demand, demand growth has begun to increase due to new data centers, increased domestic manufacturing, and electrification. However, long-standing barriers are set to limit the generation and transmission of affordable clean energy to meet this demand growth, raising costs for consumers and hampering the clean energy transition. While it is too soon to evaluate the precise pace of electricity demand growth, it is not too soon to begin identifying—and enacting—solutions.

Increased adoption of advanced transmission technologies – including dynamic line ratings, high-performance conductors, advanced power flow control devices, and topology optimization—can help expand the capacity of the electric grid quickly and cost-effectively. These technologies may not be appropriate in every setting, but researchers, regulators, and policymakers increasingly recognize that they are widely under-adopted.

A range of solutions could help support adoption *within* the current electricity system. These include policies to:

- Require transmission providers to use ATTs in certain contexts
- Require transmission providers and regulators to conduct robust analyses of the value of ATTs
- Create financial incentives for transmission providers to adopt ATTs where they can provide high net benefits
- Require transmission providers to release additional data on the grid and build digital tools to inform ATTs adoption

Although these solutions will support increased adoption, they will not eliminate the underlying incentives that discourage ATTs adoption. More transformative change, such as by shifting the responsibility of ATT planning altogether to a third party, could. This would enable the rapid buildout of transmission and the connection of new clean energy generation sources to the grid—lowering electricity prices, reducing U.S. emissions, and facilitating continued innovation in energy-intensive industries.

Brian Deese, Rob Gramlich, and Anna Pasnau (2024), "Research Commentary: A Roadmap for Advanced Transmission Technology Adoption", CEEPR RC-2024-06, MIT, September 2024.

For references cited in this story, full bibliographical information can be found in the Research Commentary.

Research.

The Impact of Financing Structures on the Cost of CO_2 Transport

By: Katrin Sievert,
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According to decarbonization pathways, carbon capture and storage (CCS) forms a core part of the mitigation technology portfolio for energy-intensive process industries. One region with high policy attention on CCS as part of the decarbonization portfolio is Europe. After a long period of hibernation since the early 2000s, CCS deployment is gaining momentum, targeting the very sectors where emissions are difficult or expensive to abate. To incentivize CCS investments, commercial-scale CO_2 transport infrastructure is needed to connect European industrial CO_2 emitters and potential underground storage sites. Developing such infrastructure involves resolving several techno-economic issues that have been addressed in previous literature, such as identifying which CO_2 transport modes are feasible, designing optimal transport routes, and estimating transport costs (Oeuvray et al., 2024). The question of how to finance the upfront investment cost, however, is typically out-of-scope. Yet it matters: Developing a transnational CO_2 transport network in Europe will require substantial initial investments. Despite its importance, the issue of how to finance CO_2 transport infrastructure is hardly addressed in the literature. However, the financing structure of transport assets is an important determinant of transport cost: Financing conditions are critical for capital-intensive assets, where large parts of the life-cycle costs are incurred upfront and need to be financed.

To fill this gap, we assess the impact of financing structures on the total cost of CO_2 transport. Given the absence of empirical data on CO_2 transport financing, we review the literature on economic ownership to identify the economic rationales that influence the choice of financing structures and to assess the impact of financing structures on the cost of capital and on operational efficiency. Several financing sources are available to provide capital for CO_2 transport assets: public finance, private finance, and regulatory asset base (RAB) finance. In terms of financing models, new projects can be financed through corporate finance structures (i.e., "on balance sheet") or project finance structures (i.e., "off-balance sheet," in a new legal entity) (Steffen, 2018).

To apply the insights from the broader economic literature on infrastructure financing to the case of CO_2 transport, we first assess which financing structures are most suitable for the financing of assets required for each CO_2 transport mode by referring to analogous industries with similar asset types and risk profiles. We then estimate the financing structure- and transport mode-specific financing cost, namely, the cost of capital, and calculate the levelized cost of transport, accounting for operational efficiency differences related to the different financing structures.

We find that the impact of financing structures on the cost of capital and, thus, the cost of CO_2 transport, varies notably by transport mode

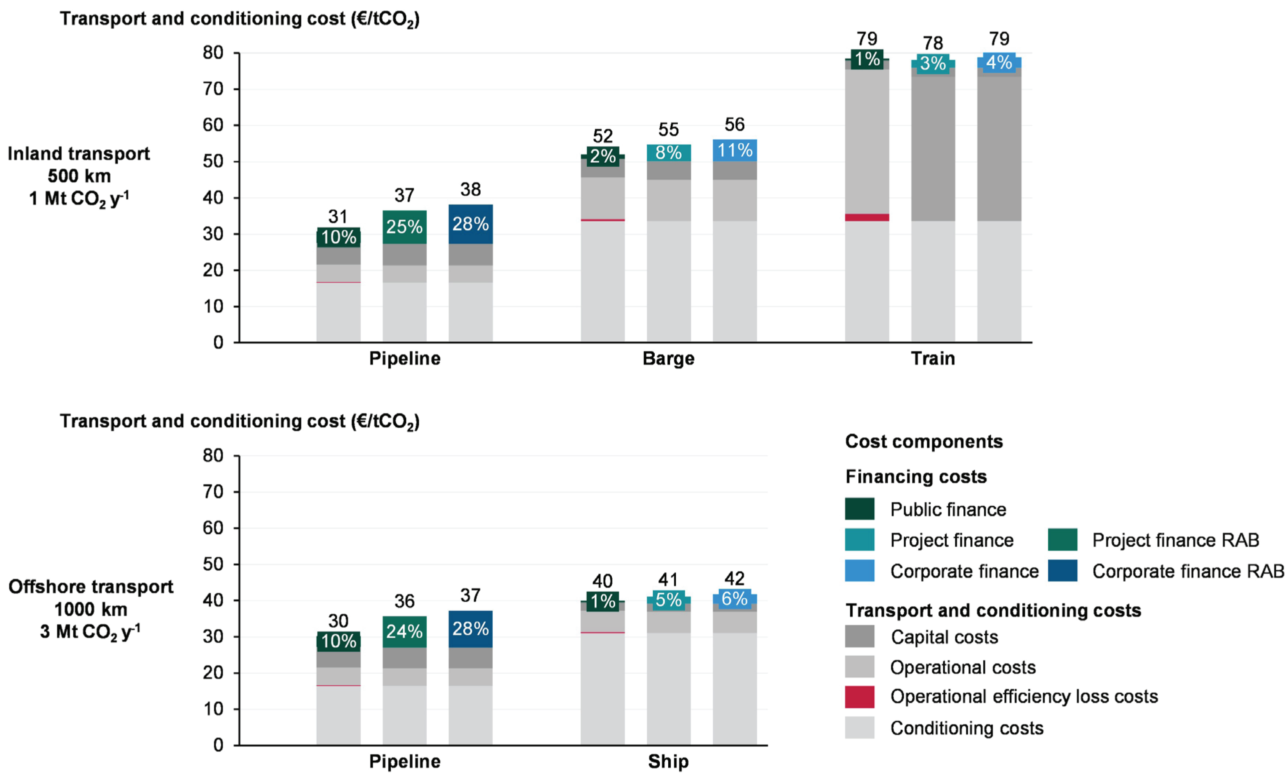

Figure 1. Levelized cost assessment of CO_2 transport and conditioning in €2022/tCO_2 under different financing structures.

but also by financing structure. Overall, our results show that onshore and offshore pipelines are the lowest-cost transport modes regardless of the financing structure, as illustrated in Figure 1. Pipelines, which require high upfront capital investments, are highly sensitive to the financing structure chosen. With a cost of capital of 8.5% or above, financing costs could account for more than half the total transport costs for onshore pipelines. In contrast, for the other CO_2 transport modes, including barges, trains and ships, we find a relatively small impact of different financing structures.

Our findings are relevant for policymakers, as the cost of financing is an important factor in the choice of a financing structure for CO_2 transport infrastructure. Generally, our results suggest that in the context studied, public finance appears to be the most cost-effective financing structure for CO_2 transport infrastructure, if the government cost of capital sets the discount rate, because the benefits of a lower cost of capital under public finance, compared to RAB and private finance, outweigh the operational efficiency losses associated with it. However, the results are contingent upon our assumptions, and, specifically, the understanding of efficiency differences both between public and private financing structures and among various types of public delivery remains limited.

Given the need to develop CO_2 transport infrastructure to meet CCS policy targets in Europe, we hope that studying the impact of financing structures on cost will expand policymakers' attention beyond the question of the total investment required toward the issue of how the financing should be structured. The analysis can inform policymakers aiming to design regulations that attract both public and private investment in CO_2 transport infrastructure, CO_2 emitters evaluating their CO_2 transport options, and project financiers and financial intermediaries considering becoming involved in CO_2 transport finance.




Katrin Sievert, Alexandru Stefan Stefanescu, Pauline Oeuvray, and Bjarne Steffen (2024), "The Impact of Financing Structures on the Cost of CO_2 Transport", CEEPR WP-2024-12, MIT, August 2024.
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Research.

Challenges to Expanding EV Adoption and Policy Responses

By: Christopher R. Knittel
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Electric vehicles (EVs) offer a vital solution in global efforts to combat climate change, especially as the transportation sector accounts for a significant share of greenhouse gas (GHG) emissions. The shift from gasoline and diesel-powered vehicles to EVs is crucial for reducing emissions. In 2022, EVs accounted for 14% of new car sales globally, with rapid growth in countries like China and Norway, where government policies support widespread adoption. However, in the U.S., EVs have been slower to gain market share, representing just 6% of new light vehicle sales in 2022. This is far below President Biden's target of 50% electric vehicle sales by 2030. Achieving higher EV adoption in the U.S. and other lagging markets requires addressing three major challenges: high costs, range anxiety, and insufficient charging infrastructure.

This paper provides a comprehensive review of initiatives, policies, and funding programs crucial for expanding EV charging networks and promoting EV adoption in the U.S. and selected countries. Through an analysis of current programs and funding mechanisms, the study explores the barriers to adoption and the ongoing efforts to enhance the accessibility of EV charging infrastructure. Additionally, it offers insights into how the U.S. can address infrastructure gaps and develop a more sustainable and inclusive transportation system, ultimately supporting broader decarbonization efforts in the transportation sector.

1. Policy Initiatives on EV Charging Infrastructure

Since 2008, the U.S. federal government has made significant investments in the electrification of the transportation sector. Initially, these programs primarily emphasized the research and development, manufacturing, and deployment of EVs. However, a portion of the funding allocated through these programs, such as the American Recovery and Reinvestment Act of 2009 and the Fixing America's Surface Transportation Act, has also been dedicated to the establishment of charging infrastructure, recognizing the crucial role it plays in supporting the widespread adoption of EVs.

The Bipartisan Infrastructure Law, enacted in 2021, marks a transformative investment in EV charging infrastructure, allocating approximately $7.5

billion specifically for EV charging stations. A central component of this initiative is the National Electric Vehicle Infrastructure (NEVI) program, which aims to strategically deploy a nationwide network of EV chargers to enhance accessibility and convenience for EV users. The NEVI program focuses on establishing charging stations along designated Alternative Fuel Corridors, ensuring that EV drivers have reliable access to charging facilities across the country.

In addition to federal efforts, various state and regulated utility policies play a crucial role in expanding EV charging infrastructure in the U.S. Many states have implemented their own programs to incentivize the installation of EV chargers, often complementing federal initiatives. These state-level policies include grants, rebates, and tax incentives for businesses and consumers who invest in charging infrastructure. Furthermore, regulated utilities are increasingly involved in supporting the development of EV charging networks through investments in infrastructure, rate structures that promote off-peak charging, and innovative programs that encourage the installation of chargers in underserved areas.

While establishing direct causal impacts of federal and state incentives on the deployment of EV charging infrastructure can be challenging, the statistics suggest significant progress in the accessibility and availability of charging options for EVs over the past decade in the U.S., aligning with the implementation of major federal initiatives.

Table 1 presents a detailed breakdown of the growth in EV chargers by country and charging levels since 2015. China leads the world in the number of EV chargers, outpacing the U.S. not only in quantity but also in quality. Notably, 40% of public chargers in China are fast chargers, which offer high power output and significantly reduce charging times. In contrast, the U.S. relies heavily on Level 1 and Level 2 chargers—slower charging options—which made up approximately 80% of available public chargers in 2021, while in Europe, this figure was even higher at around 86%. As fast chargers play a critical role in addressing range anxiety and supporting long-distance travel, expanding the U.S. public fast charger network is essential to accelerating widespread EV adoption and making electric mobility more convenient for all drivers.

The availability of EV charging stations across the U.S. demonstrates significant spatial variation. Figure 1, Panel A, highlights that out of the estimated 146,600 public EV charging ports nationwide as of June, 2023, California holds the highest share, with around 41,000 ports, representing approximately 28.1% of the total. Panel B presents the normalized data per 100 EV registrations, providing insights into the number of ports relative to the number of EVs on the road. In this context, California ranks among the lowest, with approximately 7.3 charging ports per 100 vehicles, a result driven by California's large EV population, which exceeds 563,000 EVs—far outpacing other states.

2. Policy Initiatives on EV Adoption

One of the most significant obstacles to the widespread adoption of EVs is their higher upfront purchase cost, particularly when compared to traditional gasoline-powered vehicles. The main driver of this cost differential is the price of EV batteries. Although there has been a substantial decline in battery costs over the past decade—leading to a significant reduction in the purchase price of EVs relative to their battery range—the timeline for achieving cost parity with gasoline-powered vehicles remains a subject of debate.

A key piece of legislation aimed at addressing this barrier is the Inflation Reduction Act (IRA) of 2022. Widely regarded as a historic step in the advancement of transportation electrification, the IRA extends tax incentives for all types of electric vehicles, including light-, medium-, and heavy-duty vehicles. These incentives are designed to offset the higher upfront costs of EVs, making them more accessible to consumers. The light-duty EV tax credit, which provides up to $7,500 per vehicle, is now extended through 2032, helping to promote a cleaner, more sustainable, and equitable transportation future.

Beyond federal incentives, individual states and numerous local utilities have introduced a variety of additional financial and non-financial measures to encourage EV adoption. These incentives range from rebates and tax credits to discounted electricity rates for EV charging, exemptions from High Occupancy Vehicle lane restrictions, and reduced vehicle registration fees. Some regions also offer free Smart

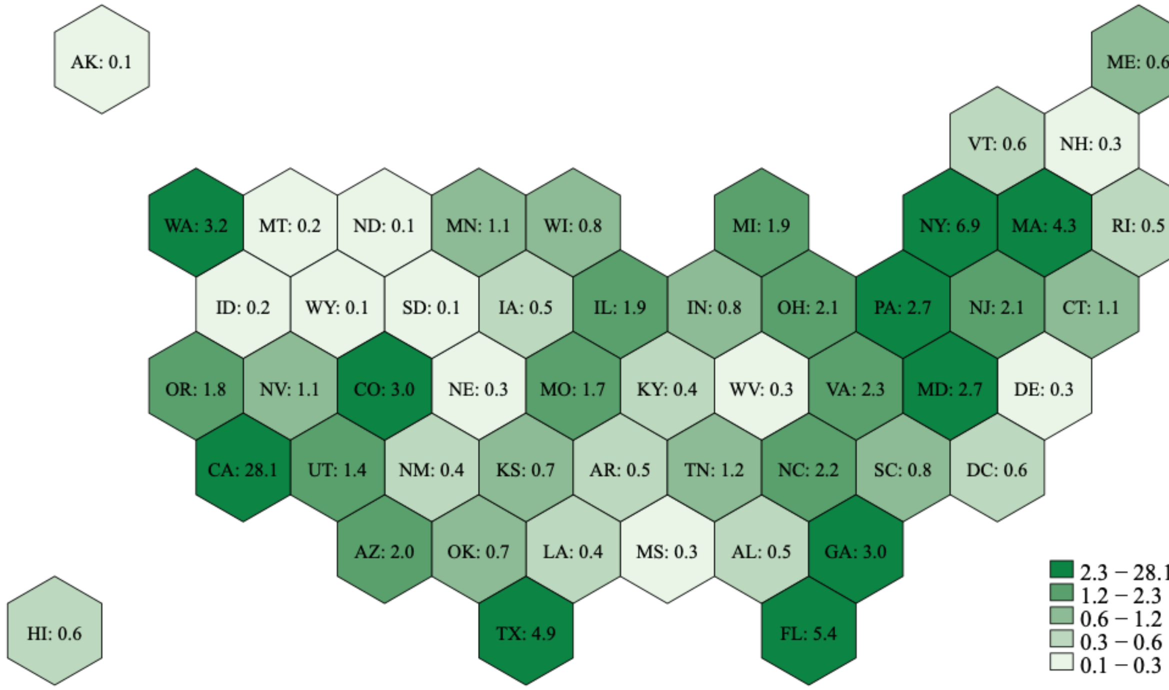
Table 1: Number of Public EV Chargers by Country and Type

	Slow			Fast		
Year	China	Europe	U.S.	China	Europe	U.S.
2015	47	61	28	12	6	4
2016	86	113	35	55	9	3
2017	131	122	40	83	11	3
2018	164	136	50	111	16	4
2019	301	187	64	215	25	13
2020	498	236	82	309	38	17
2021	677	307	92	470	49	22

Notes: This table presents the number of public EV chargers (in thousands) categorized into slow chargers and fast chargers, using data from IEA (2022).

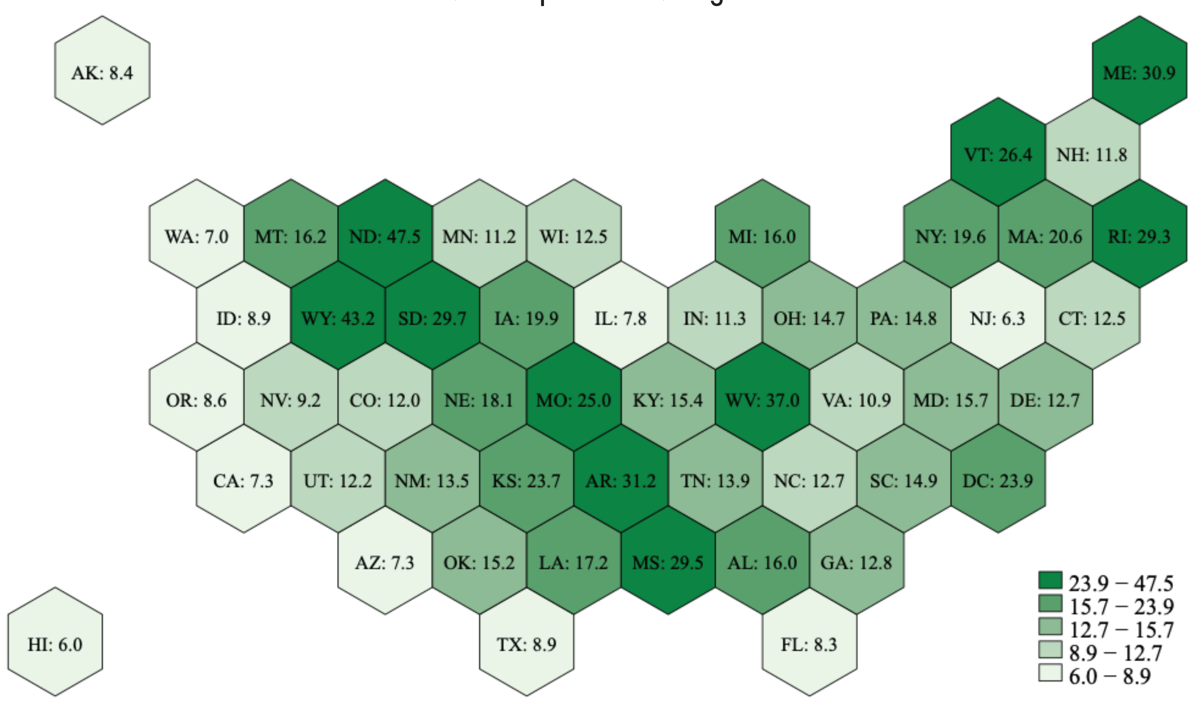
Figure 1: Distribution of Public EV Charging Ports by State.

Panel A: Percent Share



Notes: This figure shows the percentage share of public EV charging ports by state, based on data from AFDC Locator.

Panel B: Number per 100 EV Registrations



Notes: This figure shows the number of public EV charging ports per 100 EV registrations, using data from AFDC vehicle registration counts.

Table 2: Number of EVs around the World, 2021

Country/region	Sale (1,000)	EV sale share
China	3,334	16%
U.S.	631	5%
Europe	2,284	17%
U.K.	312	19%
Norway	152	86%

The table presents EV sales and sale shares for battery electric and plug-in hybrid vehicles in 2021, using IEA (2022) data.

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Christopher R. Knittel and Shinsuke Tanaka (2024), "Challenges to Expanding EV Adoption and Policy Responses", CEEPR WP-2024-16, MIT, October 2024.

Electric Vehicle Chargers or exemptions from sales and use taxes, further enhancing the economic viability of owning an EV.

However, despite these incentives, the market penetration of EVs remains modest in many countries. Globally, EVs accounted for 9% of total car sales in 2021—a fourfold increase from their market share in 2019. In the U.S., EV sales represented 5% of new car sales in 2021 (Table 2), yet they made up only 0.5% of the total registered vehicles nationwide. This growth, while encouraging, lags behind the rapid advancements seen in other regions, notably China (16%) and Europe (17%). This disparity underscores the need for continued refinement of policy strategies to accelerate EV adoption. Europe's success is particularly exemplified by Norway, where EVs captured 86% of the market share for new vehicle sales in 2021, with 152,000 electric vehicles sold.

3. Policy Challenges

We have identified four key challenges that must be addressed to create an inclusive, reliable, and sustainable charging network.

Understanding the interdependency between EV charging station deployment and EV adoption is essential, as both function as two-sided markets. Evidence suggests that subsidizing charging station development is more cost-effective than subsidizing EV purchases, particularly among early adopters who tend to be wealthier and less price-sensitive. As the EV market diversifies, policymakers must focus on establishing reliable estimates of network effects to optimize resource allocation and enhance EV uptake.

The standardization of charging connectors presents challenges, especially in the U.S. The industry is gravitating toward a dominant connector type, Tesla's NACS, which enhances compatibility but raises concerns regarding federal regulations mandating the use of CCS. Policymakers must strike a balance between fostering uniformity and encouraging competition to ensure consumer choice in an evolving market.

The uneven distribution of EV charging stations disproportionately affects low-income and environmental justice communities, exacerbating existing inequities. Addressing these disparities is vital, particularly as EV adoption expands beyond wealthier neighborhoods. Ongoing collaboration among federal, state, local authorities, and private stakeholders is necessary to ensure equitable access to charging infrastructure, especially in underserved areas.

Reliability, load balancing, and grid stability are critical concerns as EV charging infrastructure expands. Strategies to mitigate grid stress during peak charging times include deploying workplace chargers, incentivizing off-peak charging, and promoting innovative charging technologies. Thoughtful planning and consideration of these challenges are essential for sustaining EV adoption and infrastructure growth.

To accelerate the electrification of the transportation sector, it is crucial to evaluate the effectiveness of federal and local initiatives, address areas for improvement, and promote public-private partnerships to develop a reliable and inclusive EV charging network. This review highlights key regulatory insights. First, continued governmental support for EV charging infrastructure through federal fiscal policies and local incentives is essential. Second, beyond incentivizing home charger installation, regulations mandating the expansion of charging stations in new and existing buildings, workplaces, and parking areas are necessary for a more inclusive transition to electric mobility, as the EV consumer demographic broadens. Lastly, strategic initiatives—such as grid expansion, the adoption of digital technologies for smart charging, and the implementation of pricing mechanisms—are pivotal in enhancing the efficiency and effectiveness of the EV charging infrastructure.

Liftoff: The Climate Project at MIT Takes Flight

By: Peter Dizikes | MIT News

Cambridge, MA, September 18, 2024 —

The leaders of The Climate Project at MIT met with community members at a campus forum on Monday, helping to kick off the Institute's major new effort to accelerate and scale up climate change solutions.

"The Climate Project is a whole-of-MIT mobilization," MIT President Sally Kornbluth said in her opening remarks. "It's designed to focus the Institute's talent and resources so that we can achieve much more, faster, in terms of real-world impact, from mitigation to adaptation."

The event, "Climate Project at MIT: Launching the Missions," drew a capacity crowd to MIT's Samberg Center.

While the Climate Project has a number of facets, a central component of the effort consists of its six "missions," broad areas where MIT researchers will seek to identify gaps in the global climate response that MIT can help fill, and then launch and execute research and innovation projects aimed at those areas. Each mission is led by campus faculty, and Monday's event represented the first public conversation between the mission directors and the larger campus community.

"Today's event is an important milestone," said Richard Lester, MIT's interim vice president for climate and the Japan Steel Industry Professor of Nuclear Science and Engineering, who led the Climate Project's formation. He praised Kornbluth's sustained focus on climate change as a leading priority for MIT.

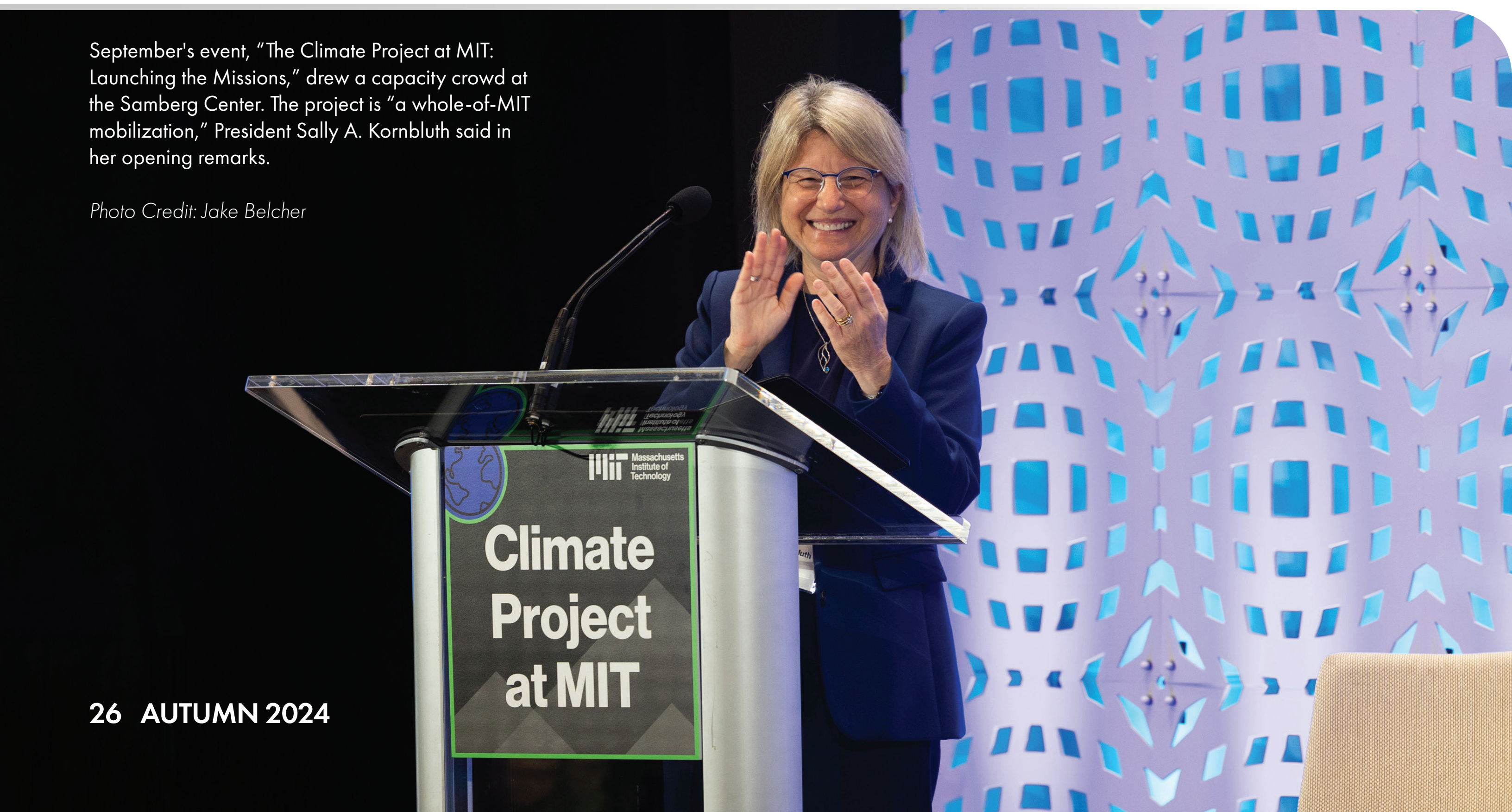
"The reason we're all here is because of her leadership and vision for MIT," Lester said. "We're also here because the MIT community — our faculty, our staff, our students — has made it abundantly clear that it wants to do more, much more, to help solve this great problem."

The mission directors themselves emphasized the need for deep community involvement in the project — and that the Climate Project is designed to facilitate researcher-driven enterprise across campus.

"There's a tremendous amount of urgency," said Elsa Olivetti PhD '07, director of the Decarbonizing Energy and Industry mission, during an onstage discussion. "We all need to do everything we can, and roll up our sleeves and get it done." Olivetti, the Jerry McAfee Professor in Engineering, has been a professor of materials science and engineering at the Institute since 2014.

"What's exciting about this is the chance of MIT really meeting its potential," said Jesse Kroll, co-director of the mission for Restoring the Atmosphere, Protecting the Land and Oceans. Kroll is the Peter de Florez Professor in MIT's Department of Civil and Environmental Engineering, a professor of chemical engineering, and the director of the Ralph M. Parsons Laboratory.

MIT, Kroll noted, features "so much amazing work going on in all these different aspects of the problem. Science, engineering, social science



September's event, "The Climate Project at MIT: Launching the Missions," drew a capacity crowd at the Samberg Center. The project is "a whole-of-MIT mobilization," President Sally A. Kornbluth said in her opening remarks.

Photo Credit: Jake Belcher

… we put it all together and there is huge potential, a huge opportunity for us to make a difference."

MIT has pledged an initial $75 million to the Climate Project, including $25 million from the MIT Sloan School of Management for a complementary effort, the MIT Climate Policy Center. However, the Institute is anticipating that it will also build new connections with outside partners, whose role in implementing and scaling Climate Project solutions will be critical.

Monday's event included a keynote talk from Brian Deese, currently the MIT Innovation and Climate Impact Fellow and the former director of the White House National Economic Council in the Biden administration.

"The magnitude of the risks associated with climate change are extraordinary," Deese said. However, he added, "these are solvable issues. In fact, the energy transition globally will be the greatest economic opportunity in human history. … It has the potential to actually lift people out of poverty, it has the potential to drive international cooperation, it has the potential to drive innovation and improve lives — if we get this right."

Deese's remarks centered on a call for the U.S. to develop a current-day climate equivalent of the Marshall Plan, the U.S. initiative to provide aid to Western Europe after World War II. He also suggested three characteristics of successful climate projects, noting that many would be interdisciplinary in nature and would "engage with policy early in the design process" to become feasible.

In addition to those features, Deese said, people need to "start and end with very high ambition" when working on climate solutions. He added: "The good thing about MIT and our community is that we, you, have done this before. We've got examples where MIT has taken something that seemed completely improbable and made it possible, and I believe that part of what is required of this collective effort is to keep that kind of audacious thinking at the top of our mind."

The MIT mission directors all participated in an onstage discussion moderated by Somini Sengupta, the international climate reporter on the climate team of The New York Times. Sengupta asked the group about a wide range of topics, from their roles and motivations to the political constraints on global climate progress, and more.

Andrew Babbin, co-director of the mission for Restoring the Atmosphere, Protecting the Land and Oceans, defined part of the task of the MIT missions as "identifying where those gaps of knowledge are and filling them rapidly," something he believes is "largely not doable in the conventional way," based on small-scale research projects. Instead, suggested Babbin, who is the Cecil and Ida Green Career Development Professor in MIT's Program in Atmospheres, Oceans, and Climate, the collective input of research and innovation communities could help zero in on undervalued approaches to climate action.

Some innovative concepts, the mission directors noted, can be tried out on the MIT campus, in an effort to demonstrate how a more sustainable infrastructure and systems can operate at scale.

"That is absolutely crucial," said Christoph Reinhart, director of the Building and Adapting Healthy, Resilient Cities mission, expressing the need to have the campus reach net-zero emissions. Reinhart is the Alan and Terri Spoon Professor of Architecture and Climate and director of MIT's Building Technology Program in the School of Architecture and Planning.

In response to queries from Sengupta, the mission directors affirmed that the Climate Project needs to develop solutions that can work in different societies around the world, while acknowledging that there are many political hurdles to worldwide climate action.

"Any kind of quality engaged projects that we've done with communities, it's taken years to build trust. … How you scale that without compromising is the challenge I'm faced with," said Miho Mazereeuw, director of the Empowering Frontline Communities mission, an associate professor of architecture and urbanism, and director of MIT's Urban Risk Lab.

"I think we will impact different communities in different parts of the world in different ways," said Benedetto Marelli, an associate professor in MIT's Department of Civil and Environmental Engineering, adding that it would be important to "work with local communities [and] engage stakeholders, and at the same time, use local brains to solve the problem." The mission he directs, Wild Cards, is centered on identifying unconventional solutions that are high risk and also high reward.

Any climate program "has to be politically feasible, it has to be in separate nations' self-interest," said Christopher Knittel, mission director for Inventing New Policy Approaches. In an ever-shifting political world, he added, that means people must "think about not just the policy but the resiliency of the policy." Knittel is the George P. Shultz Professor and professor of applied economics at the MIT Sloan School of Management, director of the MIT Climate Policy Center, and associate dean for Climate and Sustainability.

In all, MIT has more than 300 faculty and senior researchers who, along with their students and staff, are already working on climate issues.

Kornbluth, for her part, referred to MIT's first-year students while discussing the larger motivations for taking concerted action to address the challenges of climate change. It might be easy for younger people to despair over the world's climate trajectory, she noted, but the best response to that includes seeking new avenues for climate progress.

"I understand their anxiety and concern," Kornbluth said. "But I have no doubt at all that together, we can make a difference. I believe that we have a special obligation to the new students and their entire generation to do everything we can to create a positive change. The most powerful antidote to defeat and despair is collective action."

News.

The Changing Geography of "Energy Poverty"

By: Peter Dizikes | MIT News

Cambridge, MA, October 09, 2024 —

A growing portion of Americans who are struggling to pay for their household energy live in the South and Southwest, reflecting a climate-driven shift away from heating needs and toward air conditioning use, an MIT study finds.

The newly published research also reveals that a major U.S. federal program that provides energy subsidies to households, by assigning block grants to states, does not yet fully match these recent trends.

The work evaluates the "energy burden" on households, which reflects the percentage of income needed to pay for energy necessities, from 2015 to 2020. Households with an energy burden greater than 6 percent of income are considered to be in "energy poverty." With climate change, rising temperatures are expected to add financial stress in the South, where air conditioning is increasingly needed. Meanwhile, milder winters are expected to reduce heating costs in some colder regions.

"From 2015 to 2020, there is an increase in burden generally, and you do also see this southern shift," says Christopher Knittel, an MIT energy economist and co-author of a new paper detailing the study's results. About federal aid, he adds, "When you compare the distribution of the energy burden to where the money is going, it's not aligned too well."

The paper, "U.S. federal resource allocations are inconsistent with concentrations of energy poverty," is published today in the journal *Science Advances*.

The authors are Carlos Batlle, a professor at Comillas University in Spain and a senior lecturer with the MIT Energy Initiative; Peter Heller SM '24, a recent graduate of the MIT Technology and Policy Program; Knittel, the George P. Shultz Professor at the MIT Sloan School of Management and associate dean for climate and sustainability at MIT; and Tim Schittekatte, a senior lecturer at MIT Sloan.

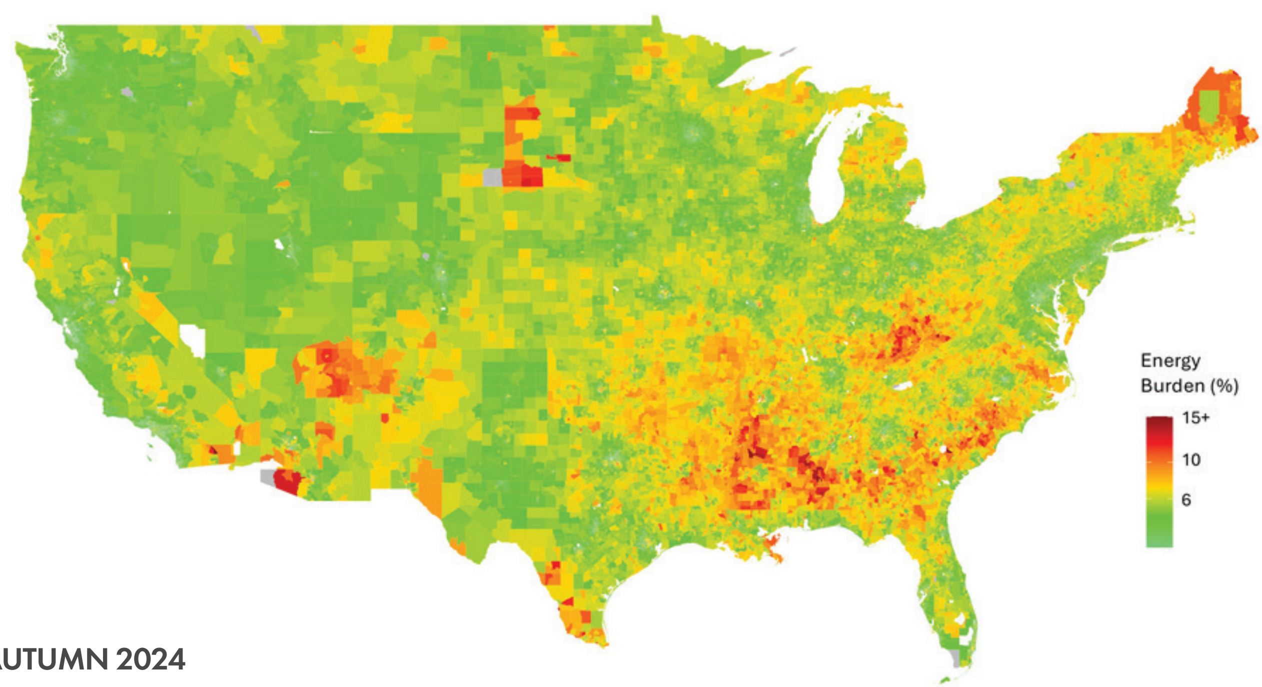
A scorching decade

The study, which grew out of graduate research that Heller conducted at MIT, deploys a machine-learning estimation technique that the scholars applied to U.S. energy use data.

Specifically, the researchers took a sample of about 20,000 households from the U.S. Energy Information Administration's Residential Energy Consumption Survey, which includes a wide variety of demographic characteristics about residents, along with building-type and geographic information. Then, using the U.S. Census Bureau's American Community Survey data for 2015 and 2020, the research team estimated the average household energy burden for every census tract in the lower 48 states — 73,057 in 2015, and 84,414 in 2020.

That allowed the researchers to chart the changes in energy burden in recent years, including the shift toward a greater energy burden in

This map shows changes in the average energy burden for U.S. households from 2015 to 2020. Households experiencing an energy burden in costs greater than 6 percent of income are classified as energy-poor. Darker shades indicate higher energy burdens, and grey areas indicate census tracts where the estimates are unavailable.



southern states. In 2015, Maine, Mississippi, Arkansas, Vermont, and Alabama were the five states (ranked in descending order) with the highest energy burden across census bureau tracts. In 2020, that had shifted somewhat, with Maine and Vermont dropping on the list and southern states increasingly having a larger energy burden. That year, the top five states in descending order were Mississippi, Arkansas, Alabama, West Virginia, and Maine.

The data also reflect a urban-rural shift. In 2015, 23 percent of the census tracts where the average household is living in energy poverty were urban. That figure shrank to 14 percent by 2020.

All told, the data are consistent with the picture of a warming world, in which milder winters in the North, Northwest, and Mountain West require less heating fuel, while more extreme summer temperatures in the South require more air conditioning.

"Who's going to be harmed most from climate change?" asks Knittel. "In the U.S., not surprisingly, it's going to be the southern part of the U.S. And our study is confirming that, but also suggesting it's the southern part of the U.S that's least able to respond. If you're already burdened, the burden's growing."

An evolution for LIHEAP?

In addition to identifying the shift in energy needs during the last decade, the study also illuminates a longer-term change in U.S. household energy needs, dating back to the 1980s. The researchers compared the present-day geography of U.S. energy burden to the help currently provided by the federal Low Income Home Energy Assistance Program (LIHEAP), which dates to 1981.

Federal aid for energy needs actually predates LIHEAP, but the current program was introduced in 1981, then updated in 1984 to include cooling needs such as air conditioning. When the formula was updated in 1984, two "hold harmless" clauses were also adopted, guaranteeing states a minimum amount of funding.

Still, LIHEAP's parameters also predate the rise of temperatures over the last 40 years, and the current study shows that, compared to the current landscape of energy poverty, LIHEAP distributes relatively less of its funding to southern and southwestern states.

"The way Congress uses formulas set in the 1980s keeps funding distributions nearly the same as it was in the 1980s," Heller observes. "Our paper illustrates the shift in need that has occurred over the decades since then."

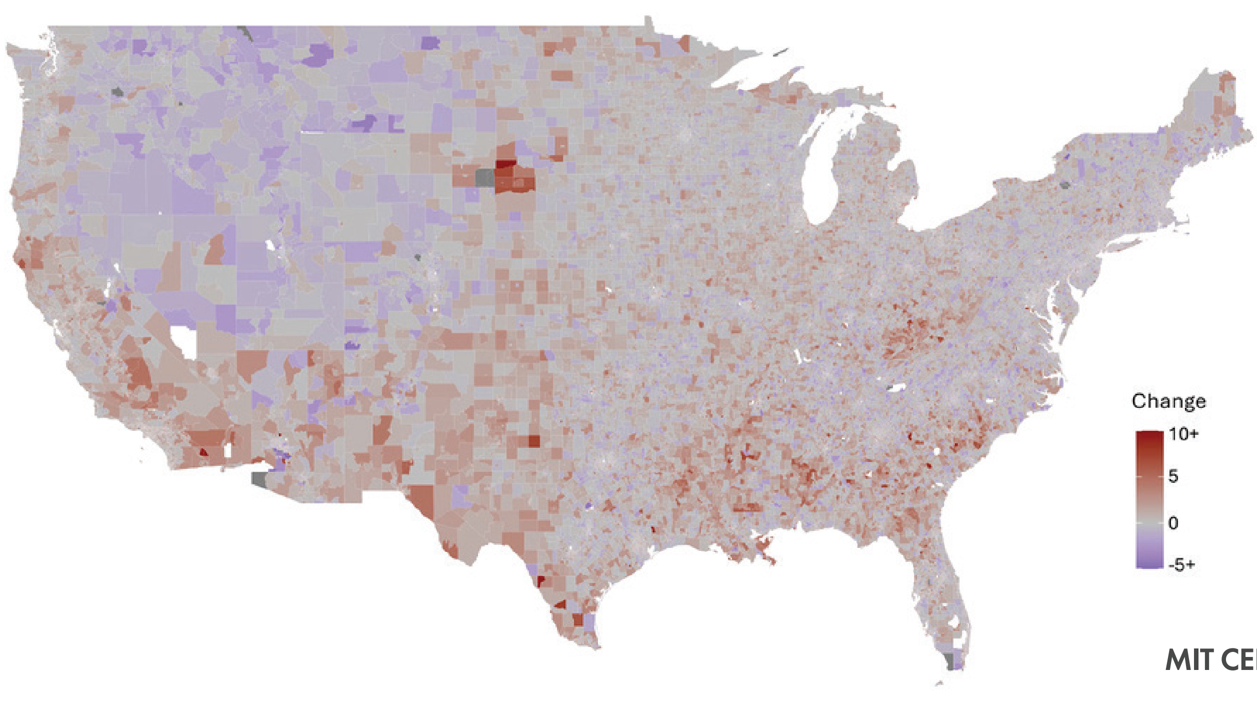
Currently, it would take a fourfold increase in LIHEAP to ensure that no U.S. household experiences energy poverty. But the researchers tested out a new funding design, which would help the worst-off households first, nationally, ensuring that no household would have an energy burden of greater than 20.3 percent.

"We think that's probably the most equitable way to allocate the money, and by doing that, you now have a different amount of money that should go to each state, so that no one state is worse off than the others," Knittel says.

And while the new distribution concept would require a certain amount of subsidy reallocation among states, it would be with the goal of helping all households avoid a certain level of energy poverty, across the country, at a time of changing climate, warming weather, and shifting energy needs in the U.S.

"We can optimize where we spend the money, and that optimization approach is an important thing to think about," Knittel says.

This map estimates the change in U.S. household energy costs, as a fraction of income, between 2015 and 2020. Blue represents tracts where the average energy burden has decreased during the period. Red represents tracts where the average energy burden has increased over time. Darker shades represent greater change. White areas indicate census tracts where the values are unavailable.



Research.

Bridging the Gaps: The Impact of Interregional Transmission on Emissions and Reliability

By: Audun Botterud, Christopher R. Knittel, John E. Parsons, Juan Ramon L. Senga, and S. Drew Story

One of the dramatic changes to the energy landscape over the last decade has been the substantial decline in the cost of wind and solar generation. Globally, the levelized cost of electricity (LCOE) for wind and solar decreased by 69% and 89%, respectively, from 2010 to 2022 (IRENA, 2022). The US also saw similar trends with construction costs for wind and solar decreasing by 25% and 58% within the same period (EIA, 2023). New investments in these technologies therefore often make economic sense on their own, even without stringent decarbonization policies. Interregional transmission can be a valuable complementary investment.

The proposed BIG WIRES Act is a piece of legislation that requires each FERC Order No. 1000 region to meet minimum interregional transfer capability (MITC) requirements (Hickenlooper and Peters, 2023). A distinctive feature of the act is that it does not prescribe where each region should build transmission. Rather, it provides a way to calculate the transfer capability requirement—the minimum between 30% of a region's peak load and 15% of its peak load plus its current transfer capability—and lets the regions decide how to meet it. This provides a more realistic, policy-driven grid expansion methodology to analyze the value of interregional transmission to the U.S. grid under current policies and deep decarbonization scenarios. We use the GenX capacity expansion model coupled with stylized heuristics that determine transmission builds to analyze four key areas: interregional

	Peak Load ($\bar{D}_r$)	Current Transfer Capability ($\hat{TC}_r$)	$MITC_r$	$\frac{MITC_r}{\bar{D}_r}$	Additional	Total	% Increase	$\frac{\text{Total}}{\bar{D}_r}$
California	70.93	19.08	21.28	30%	1.98	21.07	10%	30%
Florida	55.80	3.60	11.97	21%	8.25	11.85	229%	21%
Northeast	30.47	2.16	6.73	22%	4.50	6.66	208%	22%
Midwest	157.51	35.92	47.25	30%	13.39	49.31	37%	31%
Northwest	65.75	22.17	19.72	30%	1.73	23.90	8%	36%
New York	33.64	4.08	9.12	27%	8.84	12.92	217%	38%
Mid-Atlantic	195.35	24.01	53.32	27%	28.77	52.78	120%	27%
Southeast	160.27	23.32	47.36	30%	27.64	50.96	119%	32%
Central	59.67	10.42	17.90	30%	7.23	17.65	69%	30%
Southwest	47.17	12.40	14.15	30%	4.73	17.13	38%	36%

Table 1. Current and additional interregional transfer capability per region in the Current Policies setting (GW).

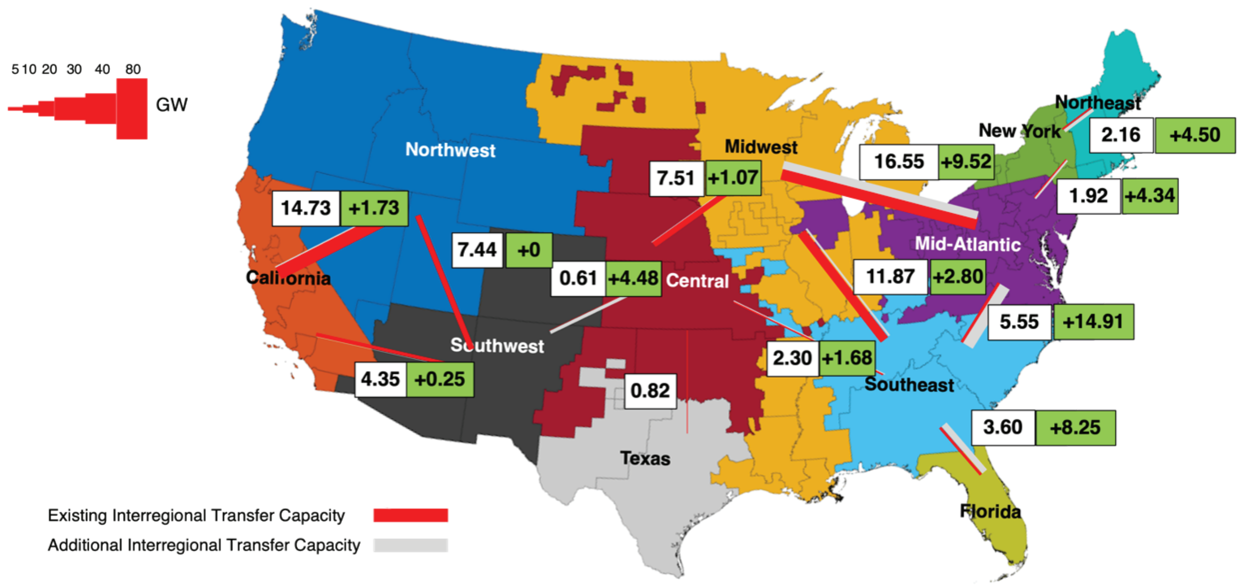


Figure 1. Current and additional interregional transfer capability per region in the Current Policies setting (GW).

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transmission builds and grid characteristics, electricity system cost savings, grid reliability during extreme weather events, and climate benefits. We consider two main scenarios for a future 2035 grid—the current policies setting and the 95% CO_2 reduction setting—and determine the impact of the BIG WIRES Act and interregional transmission on these two scenarios.

I. Interregional Transmission Builds and Cost

Table 1 shows the calculated MITC requirement and the existing and additional interregional transfer capability for each of the regions while Figure 1 shows the interregional transfer capability between regions. Both results show that most of the transmission builds are concentrated in the Eastern Interconnect owing to the way the minimum requirements are calculated and these regions' higher peak loads. We also observe that some regions build more than the prescribed minimum because its neighboring regions have higher requirements. An example would be the New York region which builds beyond its MITC to satisfy the Northeast's requirements. The blanket minimum requirements of the BIG WIRES Act can therefore induce transmission builds beyond what the requirement is. This is especially true in regions that are adjacent to only one other region.

With these transmission builds, the BIG WIRES Act leads to lower system cost in the order of $487 million and $3.21 billion annually in the Current Policies and 95% CO_2 reduction scenarios, respectively. The savings come from being able to substitute interregional transmission with capital investments in thermal generators needed to balance the intermittency of renewables in unconnected regions. The larger savings in the 95% CO_2 reduction setting emphasizes the complementary benefit of interregional transmission and VRE resources.

II. Reliability during Extreme Weather Events

Transmission infrastructure is believed to increase a power system's reliability and mitigate the impact of extreme weather events. To test this hypothesis, we assume that an extreme weather event manifests in the form of simultaneous random natural generation capacity outages over

	MITC %						
	0	10	20	30	40	50	60
Mid-Atlantic/Southeast	26,842 (0%)	25,682 (4%)	19,974 (26%)	16,350 (39%)	12,734 (53%)	10,854 (60%)	10,140 (62%)
Midwest	1,040 (0%)	1,095 (-5%)	1,007 (3%)	962 (8%)	538 (48%)	531 (49%)	507 (51%)
Florida	7,544 (0%)	5,661 (25%)	2,960 (61%)	1,678 (78%)	1,168 (85%)	506 (93%)	145 (98%)
New York	2,022 (0%)	1,539 (24%)	561 (72%)	618 (69%)	636 (69%)	589 (71%)	598 (70%)
Northeast	2,295 (0%)	1,865 (19%)	848 (63%)	814 (65%)	639 (72%)	435 (81%)	369 (84%)
California	186 (0%)	182 (2%)	181 (3%)	99 (47%)	29 (84%)	24 (87%)	14 (92%)
Texas	2,208 (0%)	2,197 (0%)	2,195 (1%)	2,196 (1%)	2,177 (1%)	2,194 (1%)	2,238 (-1%)
Southwest	77 (0%)	76 (1%)	74 (4%)	81 (-5%)	166 (-115%)	175 (-127%)	182 (-135%)
Northwest	56 (0%)	55 (1%)	55 (1%)	12 (78%)	0 (100%)	0 (100%)	0 (100%)
Central	3 (0%)	2 (26%)	0 (97%)	0 (100%)	0 (100%)	0 (100%)	0 (100%)

Table 2. Average hourly outages in MWh (% Reduction relative to MITC % = 0).

a specified period. We then develop a Monte-Carlo simulation that randomly assigns the same amount of natural gas outages in each of a thousand simulations. A dispatch model is run to calculate the average non-served energy across all the simulations.

Table 2 shows the results of these simulations across different MITC % of peak load requirements. Our results indicate that increased transmission through MITC requirements lead to a substantial reduction in average generation outages during extreme weather events. This is because regions gain the ability to import power from its neighbors when there are outages. Most of these reliability benefits are seen in the Mid-Atlantic/Southeast and the Florida regions, which coincide with the regions where most of the transmission builds under the BIG WIRES Act are done. These results provide evidence supporting the need for more transmission to ensure grid reliability during extreme weather events.

III. Climate Benefits

Finally, we look at the climate benefits of interregional transmission and the BIG WIRES Act. We find that increased transmission consistently leads to lower CO_2 emissions as seen in Figure 2. This is again because of more renewables in a more interconnected grid and the consequent reduction in generation from fossil fuels. In particular, the BIG WIRES Act leads to 43 million metric tons (Mmt) less CO_2 emissions compared to when there is no BIG WIRES Act. This translates to roughly $8.2 billion of annual savings based on the EPA's proposed estimate for the social cost of carbon of $190 per metric ton (EPA, 2023).

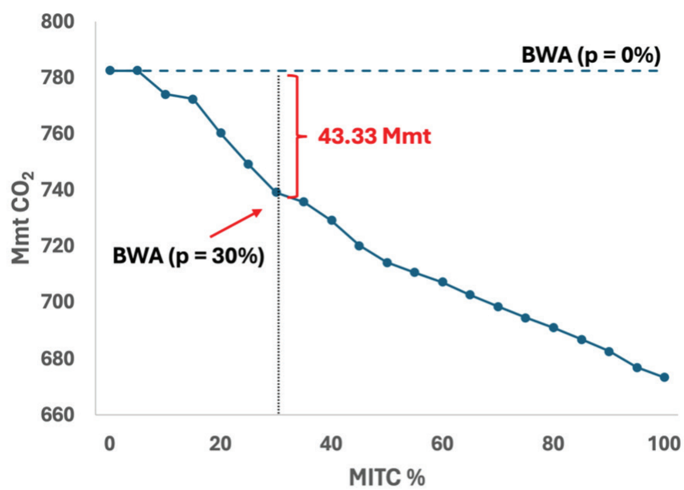

Figure 2. Total Emissions per MITC % under Current Policies

In summary, our results show that there are many benefits that arise from building interregional transmission and the BIG WIRES Act. The act leads to an increase in interregional transmission builds across the entire US, concentrated in the Eastern Interconnect. It also reduces system cost by reducing reliance on fossil fuel generators in favor of VRE resources. Interregional transmission and the BIG WIRES Act reduce the impact of extreme weather events by allowing regions to import power from its neighbors during outages. Lastly, there is a reduction in CO_2 emissions because of an increase in VRE resources with more interregional transmission.

Audun Botterud, Christopher R. Knittel, John E. Parsons, Juan Ramon L. Senga, and S. Drew Story (2024), "Bridging the Gaps: The Impact of Interregional Transmission on Emissions and Reliability", CEEPR WP-2024-13, MIT, August 2024. For references cited in this story, full bibliographical information can be found in the Working Paper.

Personnel.

Introducing CEEPR's New Researchers in 2024

We are pleased to welcome these new researchers to CEEPR during the new academic year at MIT:

Jasdeep Mandia, *Postdoctoral Associate*

Jasdeep Mandia is an environmental and urban economist currently working as a Postdoctoral Associate at the MIT Center for Energy and Environmental Policy Research. He earned his Ph.D. in Economics from Arizona State University. His research delves into household amenity valuation, residential sorting, and environmental justice, focusing on noise pollution, wildfires, electricity, and water access. Before his Ph.D., Jasdeep gained research experience in India, working with organizations such as J-PAL South Asia and UChicago EPIC. He also briefly worked with the World Bank. His educational background includes engineering and an MBA.

Jack Morris, *Graduate Research Assistant*

Jack Morris works with Director Christopher Knittel to explore the effect residential heating electrification on the growth and shape electric load profiles and how that impacts investment decisions in new generation, storage, and transmission technologies. Jack also works with Deputy Director John Parsons to study how the costs and benefits of new interregional transmission are distributed among regional utilities. Formerly, while a Master's student in MIT's Technology & Policy Program, Jack developed a retrofit modeling capability for MIT's capacity expansion model GenX in order to estimate the potential for retrofitted generating assets to lower costs, keep energy workers employed, ensure grid reliability, and enable a smooth energy transition. Jack is now a Ph.D. student in MIT's Social & Engineering Systems program in the Institute for Data, Systems, and Society.

Ruby Aidun, *Graduate Research Assistant*

Ruby Aidun is a Graduate Research Assistant at the MIT Center for Energy and Environmental Policy Research working with Dr. John Parsons. Her current research focuses on the deployment of grid-level battery storage and the role it plays as the energy sector transitions to variable renewable energy sources. Ruby is pursuing an M.S. in Technology and Policy at MIT. She holds a bachelor's degree in materials science and engineering from Columbia University.

Fischer Argosino, *Graduate Research Assistant*

Fischer Argosino is pursuing an S.M. in MIT's Technology and Policy Program while serving as a Graduate Research Assistant at the MIT Center for Energy and Environmental Policy Research and the MIT Climate Policy Center. He is passionate about developing solutions for expanding access to affordable clean energy technologies. His current research with Director Christopher Knittel focuses on optimizing federal resource allocation for the Low-Income Home Energy Assistance Program (LIHEAP). Before joining MIT, Fischer graduated *magna cum laude* from the Colorado School of Mines with a B.S. in Mechanical Engineering and a minor in Public Affairs.

Nathan Collett, *Graduate Research Assistant*

Nathan Collett is a Graduate Research Assistant supporting the policy and resilient cities missions of the Climate Project at MIT. He is currently pursuing an S.M. in the MIT Technology and Policy Program as a Fulbright Scholar, with thesis research focused on the political economy of sustainable building design. Nathan previously worked in a specialized social and behavioural science research unit of the Privy Council Office of Canada, where he provided evidence-based policy advice to the Prime Minister and Cabinet on climate change and threats to democratic stability. Previously, he earned a B.A. & Sc. from McGill University, where he was a student fellow at the Research Group on Constitutional Studies and the founding director of the McGill Journal of Human Behaviour. Nathan grew up in Vancouver, British Columbia, immersed in nature, good books, and social democratic politics.

Cem Keske, *MIT Visiting Student*

Cem Keske is a visiting student at MIT CEEPR, specializing in energy storage risk management for his master's thesis. He is involved in the "Stored Energy Reserve Market for Grid Resource Adequacy" project, where he builds optimization models to enable making risk-aware energy storage decisions under renewable energy uncertainty. Previously, Cem was at ETH Zurich, with a focus on electricity markets and optimization. His recent work on carbon- and revenue-optimal, degradation-aware battery arbitrage operation was published in Energy Conversion and Management (2024). He holds a B.Sc. in Electrical & Electronics Engineering from EPFL.

Grant Lee, *Graduate Research Assistant*

Grant Lee is a Graduate Research Assistant at the MIT Center for Energy and Environmental Policy Research and is currently pursuing an S.M. in Technology and Policy at MIT. His research utilizes the GenX optimization model to create insights for international electricity trading, hydroelectric resource utilization and management, and sustainable economic development. Before coming to MIT, Grant worked as an English teacher in Seoul, South Korea. He holds a B.S. in environmental engineering and a B.A. in government from the University of Texas at Austin.

Clara Park, *Graduate Research Assistant*

Clara Park is pursuing an S.M. in MIT's Technology and Policy Program while serving as a Graduate Research Assistant at the MIT Center for Energy and Environmental Policy Research. Her research focuses on the role of Battery Energy Storage Systems (BESS) in the energy market. Before joining CEEPR, Clara worked as a mechanical engineer at AECOM and earned her B.A.Sc. in Sustainable Energy Engineering from Simon Fraser University.

Jaclyn Rambarran, *Graduate Research Assistant*

Jaclyn Rambarran is currently pursuing an S.M. In Technology and Policy at MIT. Her current research with Christopher Knittel focuses on the potential for electric school buses to serve as distributed storage resources for peak load mitigation. Jaclyn holds a bachelor's degree in mechanical engineering and a certificate in sustainable energy from Princeton University. Jaclyn comes to MIT from Eversource, where she managed the statewide evaluation and measurement activities required to establish the value of all Mass Save energy efficiency, demand response, and decarbonization programs. Jaclyn is passionate about broadening our collective understanding of cost-effective solutions for climate change mitigation and energy resilience.

Events.

Recent and Upcoming Conferences:

Information on these events is available on our website, where Associates can also access presentation slides and recordings: ceepr.mit.edu/events

2024 CEEPR & EPRG European Energy Policy Conference

September 26-27, 2024
Copenhagen, Denmark
in partnership with the University of Cambridge, Technical University of Denmark, and Copenhagen Business School

Fall 2024 CEEPR Research Workshop

December 3-4, 2024
Hotel Washington
Washington, D.C.

Spring 2025 CEEPR Research Workshop

June 10-11, 2025
Royal Sonesta
Cambridge, Massachusetts

Publications.

Recent Working Papers:

WP-2024-16
Challenges to Expanding EV Adoption and Policy Responses
Christopher R. Knittel and Shinsuke Tanaka, October 2024

WP-2024-15
The Efficiency of Dynamic Energy Prices
Andrew J. Hinchberger, Mark R. Jacobsen, Christopher R. Knittel, James M. Sallee, and Arthur A. van Benthem, October 2024

RC-2024-06
Research Commentary: A Roadmap for Advanced Transmission Technology Adoption
Brian Deese, Rob Gramlich, and Anna Pasnau, September 2024

WP-2024-14
Choosing Climate Policies in a Second-best World with Incomplete Markets: Insights from a Bilevel Power System Model
Emil Dimanchev, Steven A. Gabriel, Stein-Erik Fleten, Filippo Pecci, and Magnus Korpås, September 2024

WP-2024-13
Bridging the Gaps: The Impact of Interregional Transmission on Emissions and Reliability
Audun Botterud, Christopher R. Knittel, John E. Parsons, Juan Ramon L. Senga, and S. Drew Story, August 2024

WP-2024-12
The Impact of Financing Structures on the Cost of CO_2 Transport
Katrin Sievert, Alexandru Stefan Stefanescu, Pauline Oeuvray, and Bjarne Steffen, August 2024

RC-2024-05
Research Commentary: Understanding the Price Cap on Russian Oil and Its Role in Depressing Russian Oil Revenues
Catherine Wolfram, August 2024

WP-2024-11
Climate Policy Reform Options in 2025
John Bistline, Kimberly A. Clausing, Neil R. Mehrotra, James H. Stock, and Catherine Wolfram, July 2024

WP-2024-10
Bidding in Uniform Price Auctions for Value Maximizing Buyers
Negin Golrezaei and Sourav Sahoo, July 2024

WP-2024-09
Optimizing Mineral Extraction and Processing for the Energy Transition: Evaluating Efficiency in Single versus Joint Production
Mahelet G. Fikru and Ilenia G. Romani, July 2024

WP-2024-08
Shedding Light on Green Claims: The Impact of a Closer Temporal Alignment of Supply and Demand in Voluntary Green Electricity Markets
Hanna F. Scholta and Maximilian J. Blaschke, June 2024

WP-2024-07
EU and US Approaches to Address Energy Poverty: Classifying and Evaluating Design Strategies
Peter Heller, Tim Schittekatte, and Carlos Batlle, June 2024

RC-2024-04
Research Commentary: U.S. Leadership in Scaling Capital for Multilateral Clean Energy Finance
Lily Bermel, Brian Deese, Brad Setser, Tess Turner, and Michael Weilandt, June 2024

RC-2024-03
Research Commentary: Evaluating the Impact of the Connect the Grid Act for Texas
Audun Botterud, Christopher R. Knittel, John E. Parsons, Juan Ramon L. Senga, and S. Drew Story, June 2024

All listed working papers in this newsletter are available on our website at:
ceepr.link/workingpapers

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The MIT Climate Project includes six "missions," broad areas where MIT researchers can develop innovations and try to implement them. On September 16, 2024, MIT held the first public conversation between the mission directors and the larger campus community.

Photo Credit: Jake Belcher

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