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Editorial.

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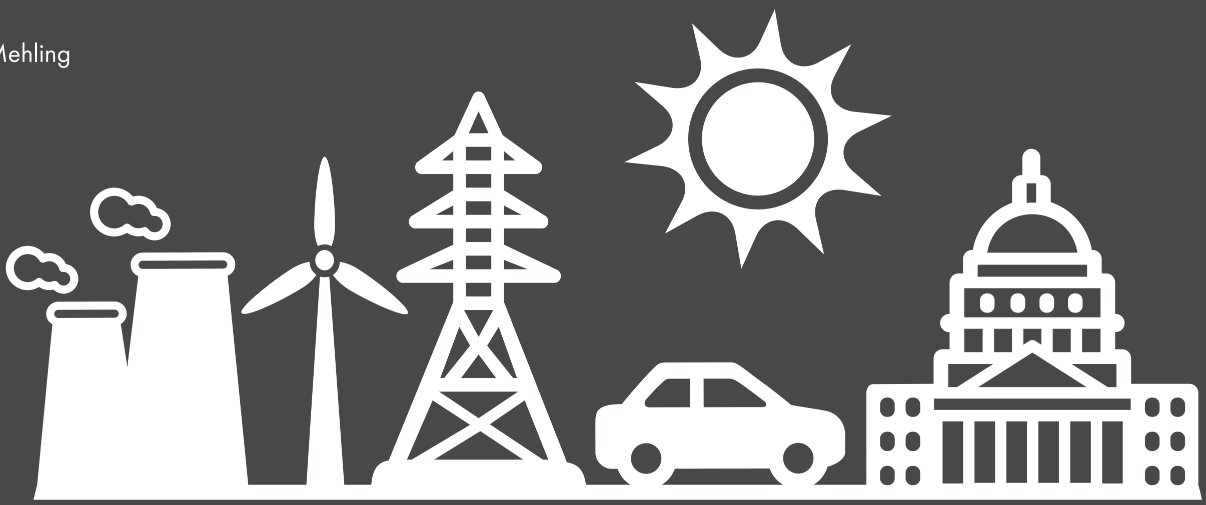
Coming off of the hottest year on record, 2024 has continued to underscore both the urgency and challenges of the global energy transition. Even as the impacts of a changing climate are felt with growing frequency and intensity, action on decarbonization is facing headwinds from multiple directions that cast uncertainty over the pace and direction of policy progress. More voters than ever will participate in national elections around the world this year, for instance, with climate and energy policies often on the ballot. Already, a resurgence of industrial policies in advanced economies has seen unprecedented levels of public support for decarbonization efforts justified with the simultaneous advancement of social, economic and political objectives, including competition with geopolitical adversaries, but has also elicited concerns about increased protectionism and fragmentation of the global economy. With its Clean Investment Monitor, CEEPR has helped track the staggering flows of new investment in the manufacture and deployment of low-carbon technologies in the United States, much of it catalyzed by industrial policy measures such as the Inflation Reduction Act. At the same time, project cancellations and delays due to rising capital costs, permitting and siting bottlenecks, labor shortages, and other barriers have constrained the potential impact of such policies, offering a reminder of the complexity of the required transformation, and with it the value of research efforts such as the ongoing Roosevelt Project that shed light on these complexities.

In all this, MIT continues to chart its role and responsibility as an institution of higher education and cutting-edge research in confronting the climate challenge. Earlier this spring, MIT President Sally Kornbluth announced a new Climate Project that aims to focus the talent and resources concentrated at MIT on solving critical climate problems at the required speed and scale. With an initial commitment of $50 million in Institute resources, the new project marks the largest direct investment MIT has ever made to advance its work on climate, and represents a new strategy for accelerated, university-led innovation. It will operate through three interconnected components: Climate Missions, Climate Frontier projects, and a Climate HQ. Alongside the Climate Project, MIT's Sloan School of Management is launching a new center, the MIT Climate Policy Center, to provide evidence-based climate policy research and help inform and support local, state, national, and international policymakers. With a $25 million investment by MIT Sloan, the Climate Policy Center will collaborate with all faculty, departments, centers, and initiatives across MIT engaged in climate policy research and outreach to forge relationships with relevant policymakers. It will also direct new research efforts to advance evidence-based climate policy, and offer a central resource for students interested in engaging more deeply with, and affecting, public policy. The Climate Policy Center will be led by CEEPR faculty director Christopher Knittel, the George P. Shultz Professor of Energy Economics, and future issues of this newsletter will provide updates on its objectives and activities.

Michael Mehling



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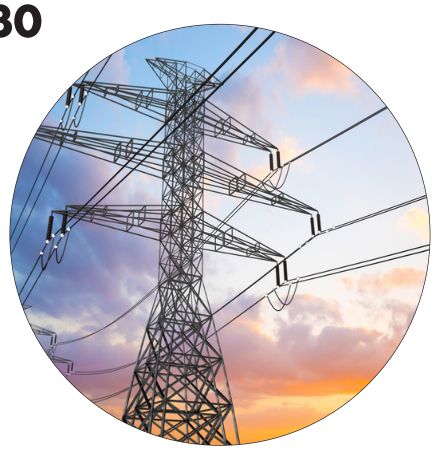

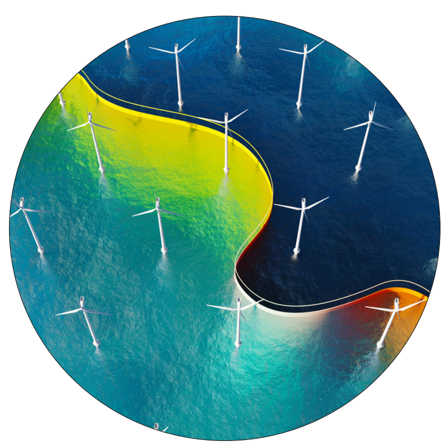

Research.

Consequences of the Missing Risk Market Problem for Power System Emissions

By: Emil Dimanchev, Steven A. Gabriel, Lina Reichenberg, and Magnus Korpås

Climate policy goals call for substantial investments in low-carbon generation and storage technologies. Whether such investments materialize will depend in large part on the financial risk that investors face and their ability to manage it.

Firms typically manage risk using financial contracts that insure them against unfavorable realizations of the future. In electricity markets, an important hedging strategy is the use of forward contracts, such as power purchase agreements (PPAs), between investors and consumers. However, markets for such contracts are generally incomplete, leaving investors unable to hedge all of the risk they face. Our research investigates the implications of this missing market problem for societal goals to decarbonize power systems.

The main question we ask is how the problem of missing risk markets impacts future power system emissions. To address this question, we model how investors' risk exposure influences their investment decisions, and thus the future technology mix.

The common approach to assessing power system investments under uncertainty uses stochastic optimization. This method assumes that investors consider multiple scenarios of the future, but that their objective is to merely maximize their expected future profit, implying that they are neutral toward risk, i.e., the shape of their profit's uncertainty distribution.

To explore the role of risk, we developed a new model of generation expansion, which has two distinguishing features. First, our model represents investors' preference to avoid risk (also known as risk aversion). Second, our model captures the incompleteness of risk markets, by taking a game theoretic approach to modeling power system investments.

Our model represents a perfectly competitive energy-only market. In it, risk-averse investors maximize profit under future uncertainty and constraints that describe their preference to avoid risk. A system operator agent dispatches the technologies deployed by investors to meet power system demand at the lowest cost.

The experiments we perform consider a stylized power system featuring four common technologies: gas plants, onshore wind, solar photovoltaic,

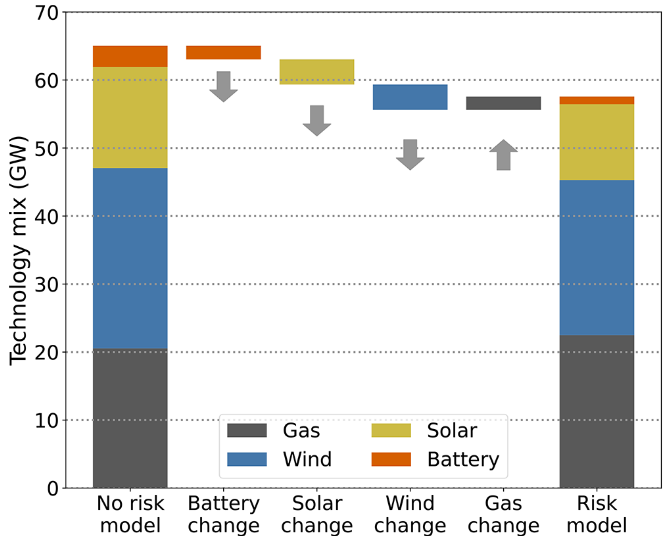

Figure 1. Effects of risk exposure on technology investments.

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Emil Dimanchev, Steven A. Gabriel, Lina Reichenberg, and Magnus Korpås (2023), "Consequences of the Missing Risk Market Problem for Power System Emissions", CEEPR WP-2023-19, MIT, November 2023.




and Li-ion batteries. We include two sources of uncertainty. First, there is uncertainty in annual electricity demand, which is modeled by scaling overall demand up and down by 25%. This represents, for example, the uncertainty in new demand from electrification and hydrogen electrolysis. Second, we model gas price uncertainty by specifying alternative scenarios that scale the gas price up and down by 25%.

The purpose of our analysis is to indicate the direction in which the missing market problem skews power system behavior. An important caveat is that we assume markets for risk to be missing (rather than merely incomplete). In other words, we assume away the existence of PPA contracts or similar financial contracts. Hence, the magnitude of our numerical results represents an upper bound on the extent to which the missing market problem affects investment decisions.

The figure above illustrates the effects of risk-exposure on technology investments. It displays results from two cases. First, we used the traditional approach to model generation expansion under uncertainty: namely, we assumed investors to be risk-neutral, which makes risk market completeness irrelevant. This is labeled as the "No risk model" in the figure. Second, we model a system with a missing market problem, namely where investors are risk-averse and risk markets are missing (in which case investors are fully exposed to the financial risk stemming from future uncertainty). This case is labeled as "Risk model" in the figure.

As illustrated, we find that the missing market problem skews the capacity mix away from wind, solar, and batteries and toward gas, relative to assuming risk neutrality. These results show that renewable and storage investments are relatively more sensitive to the risks they face compared to gas. As variable renewable and storage capacities decrease, the end result is higher power system emissions.

What explains these results? It is often thought that renewables' capital intensity is what makes investments particularly dependent on risk exposure. This is because the more capital-intensive a technology, the more a given risk premium increases its overall cost. While we capture this effect, we also model how risk premia differ between technologies. We show that gas plants face more risk than variable renewables, as the former rely on rare events of scarcity pricing. Instead of capital intensity, our analysis shows that the observed investment effects are largely driven by how sensitive technology investments are to changes in their total cost. Wind and solar capacities are adversely affected by the missing market problem because the variability of these technologies make investment relatively sensitive to cost increases.

We also model optimal risk-averse planning, where risk markets are effectively complete. In this case, it is optimal to build more wind, solar, and storage capacity than are deployed in the case of missing markets. Wind and solar provide value by reducing consumers' exposure to risk stemming from demand and gas price uncertainty.

Overall, our research shows that the missing risk market problem increases power system emissions. While the problem of missing markets is not new, we show that addressing it would also contribute to climate policy objectives. This finding strengthens the case for policy measures that enable investors to efficiently manage risk. Such measures include support for greater use of long-term contracting, instruments such as New York's index renewable energy credit contracts, or contracts for differences.

David P. Brown and David E. M. Sappington (2023), "Designing Incentive Regulation in the Electricity Sector", CEEPR WP-2023-20, MIT, November 2023.

Research.

Designing Incentive Regulation in the Electricity Sector

By: David P. Brown and
David E. M. Sappington

Competition compels industry suppliers to serve the best interests of consumers in many sectors of the economy. Intense competition to secure the patronage of consumers can compel suppliers to deliver high-quality services and charge prices that reflect realized production costs, generating only a normal profit for suppliers in the long run. Competition also compels suppliers to find new ways to control costs and to enhance service quality as industry conditions change.

Although competition can enhance consumer welfare in many industries, competition can be prohibitively expensive in industries with considerable infrastructure needs and pronounced scale economies. To illustrate, in network industries such as the electricity sector, firms could in principle compete by constructing duplicative transmission and distribution (T&D) electricity networks. However, when these duplicative costs are extremely large (as they typically are in the case of electricity T&D networks), consumers can be better served by well-designed regulation of a single supplier than by competition among suppliers. A regulator can protect consumers in part by limiting the prices that the monopoly network charges for its services, and by specifying the minimum levels of service quality that the network must deliver.

Consumers can be well served by regulation that strives to replicate the discipline of competitive markets. In principle, a regulator could employ a "command and control" policy that directs the T&D network owner to employ the most efficient technology, deliver the welfare-maximizing level of service quality, and set prices to ensure only a normal profit for the network owner when it operates at minimum cost. In practice, regulators seldom have the information required to ensure that command and control regulation can replicate the discipline of competitive markets. Regulated suppliers often have better information than regulators about prevailing industry conditions. Therefore, regulators may be better able to replicate competitive discipline and achieve other relevant goals if they can induce regulated suppliers to employ their superior knowledge of industry conditions to achieve the relevant goals. This is the essence of incentive regulation, which can be viewed as the implementation of rules that induce a regulated firm to employ its privileged information to achieve regulatory goals.

This paper reviews the basic principles of incentive regulation and examines how incentive regulation can be employed to enhance performance in the electricity sector. The paper begins by reviewing how the electricity sector has evolved, and by discussing the nature and extent of industry regulation that has been implemented. In many jurisdictions, competition prevails in the generation and retail segments, but regulation governs activities in the T&D sectors. Consequently, the paper focuses on the design and implementation of incentive regulation in the T&D segment of the electricity sector.

The paper emphasizes how the regulator's task of designing and implementing incentive regulation is complicated by her limited information about the capabilities and operations of the firms she regulates. The paper reviews particular forms of incentive regulation that are employed in practice, including price cap regulation and earnings sharing regulation. Price cap regulation sets the prices that the regulated firm can charge below levels that would be set if the firm operated under cost-of-service regulation. Earning sharing regulation requires the firm to share a fraction of its realized earnings above or below specified thresholds with consumers. Both of these policies seek to motivate the firm to employ its superior knowledge of industry conditions to reduce its operating costs. They do so by rewarding the firm for realized cost reductions with a portion of the associated gains. The paper emphasizes the fact that the policy that best motivates a regulated supplier to operate efficiently and to serve the best interests of consumers varies with the nature and extent of the regulator's information, and with the policy instruments at her disposal.

In principle, policies that reward cost reduction can encourage the regulated firm to reduce the level of service quality it delivers. We explain how incentive regulation plans can be designed to motivate cost reduction and simultaneously maintain high levels of service quality. For example, a target level of service quality can be specified, and financial rewards or penalties for realized service quality that exceeds or falls below the identified target can be specified. Such policies have been employed in practice. In Hawaii, for example, regulated suppliers are penalized if realized service quality is significantly below historic levels of service quality. We explain both how incentive regulation can be designed to induce desired levels of traditional dimensions of service quality that pertain to the frequency and length of power outages, and how it can be designed to ensure grid resiliency. Resiliency efforts seek to limit damages from relatively unlikely, but particularly detrimental, events. These events include severe weather (e.g., hurricanes or floods), wildfires, and cyber or terrorist attacks.

In the coming decades, the T&D sector will require substantial investment to replace aging infrastructure, to modernize the network, and to meet the anticipated growth in electricity demand. Consequently, it is important to structure regulatory policy to induce both the efficient levels and the efficient types of investment. Doing so can be particularly challenging as distributed energy resource (DERs) technologies such as rooftop solar, electric vehicles, and demand-side management become more widespread. The presence of DERs calls for changing the traditional policy of undertaking large-scale centralized investments to accommodating and leveraging dispersed DERs that are located closer to the point of electricity consumption. Utilities can have little incentive to make investments that rely on or accommodate DERs under traditional regulatory frameworks. We review new regulatory policies that are being employed to motivate utilities to invest in the efficient mix of traditional and DER assets, and to reduce system peaks to reduce investment needs altogether. We also explain how incentive regulation policies can be designed to achieve environmental objectives.

The paper also reviews the empirical evidence on the effects of incentive regulation. The literature suggests that incentive regulation has induced substantial cost reduction in the energy sector and more broadly. The literature also suggests that incentive regulation has enhanced service quality when the regulatory policy includes explicit financial incentives to improve quality, but may not have done so more generally.

The paper concludes by identifying important directions for further research. To illustrate, energy regulators have implemented a wide array of incentive regulation plans in recent decades. Ubiquitous sharing of experiences with incentive regulation—both successes and failures—would be valuable. Additional empirical research that systematically controls for relevant differences across regulatory jurisdictions is needed to identify the particular forms of incentive regulation that best achieve desired goals in specific environments. Additional research is also required to determine how traditional forms of incentive regulation should be modified as new technologies and new industry structures emerge in the energy sector.

Research.

The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States

By: Paul L. Joskow

Incentive regulation mechanisms have been applied for many years to the regulation of electric utilities in countries other than the U.S., including Great Britain, Chile, Argentina, Japan, New Zealand, Australia, and Canada. In an earlier paper (Joskow 2014, p. 310), Joskow concluded "Formal comprehensive incentive regulation mechanisms have been slow to spread in the U.S. electric power industry [reference omitted], though rate freezes, rate case moratoria, and other alternative regulatory mechanisms have been adopted in many states, sometimes informally, since the mid-1990s." The early applications of incentive regulation principles in the electric power sector tended to be very partial (e.g. focused on the performance of generating plants, Joskow and Schmalensee, 1986, p. 39), quasi-automatic adjustment mechanisms in response to high rates of inflation in the 1970s and early 1980s, or were temporary de facto price cap mechanisms (e.g. short-term rate freezes) that emerged as settlements of rate cases, often in connection with vertical and horizontal restructuring, stranded cost recovery and mergers, especially in the late 1990s and early 2000s as industry restructuring occurred. Since 2015, the situation regarding the applications of incentive regulation mechanisms to electric distribution companies in the United States has changed considerably. Incentive regulation mechanisms of some type have now been introduced into the electricity distribution regulatory process in a growing number of U.S. states.

Comprehensive incentive regulation mechanisms have been or are now being introduced or evaluated in about a dozen states. But these initiatives are never called "incentive regulation" by regulators and policy makers in the U.S. The policy phrases used routinely now are "performance-based regulation" (PBR) or "alternative regulatory mechanisms (ARM)." Despite the extensive theoretical literature and details of optimal regulatory mechanism design in different contexts that has emerged from it, there are very few clearly visible footprints in the policy discussion and the design of PBR mechanisms in practice in the U.S. Nevertheless, several of the more comprehensive mechanisms introduced to regulate electricity distribution in the U.S. have features that can be readily found in the theoretical incentive regulation literature even if the relationships between the theory and applications are not specified clearly.

The goals of mitigating the regulated monopoly's market power, stimulating cost efficiencies and innovation, while meeting economic and legal constraints that require regulatory mechanisms to allow regulated firms to cover their "reasonable" costs, continue to guide the evolution of PBR mechanisms for electric distribution utilities in the U.S. Efforts to provide incentives to distribution companies to support state decarbonization goals have now been added to this list. Overall, PBR applied to electricity distribution in the U.S. is best viewed as a complement to cost of service regulation (COSR), not a complete substitute, as Laffont and Tirole (1993) recognize.

The use of standard theoretical and empirical PBR concepts in the regulation of electricity distribution has not extended to the regulation of transmission owners and independent system operators by the Federal Energy Regulatory Commission (FERC). The state of PBR applied to transmission companies and the system operator are far more advanced in Great Britain, both during the "RPI-X" (a price cap that is adjusted for general movements in input prices and an assumed target rate of productivity growth) (Joskow, 2014, pp. 305) period (Joskow, 2014, pp. 326-332), and under the more recent RIIO (Revenue = Inputs + Innovation + Outputs) reforms. This is despite, or perhaps because of, the dramatic shift of regulatory responsibility for transmission rates and services from state regulators to the Federal Energy Regulatory Commission (FERC) since the late 1990s, especially where vertically integrated utilities have unbundled transmission service from distribution and generation. Moreover, non-profit independent system operators (single state ISOs or multi-state RTOs) now manage the operation of both organized competitive wholesale markets for electricity in conjunction with the management of the operation of the transmission networks serving about 2/3 of the retail customers in the U.S. They also have responsibility for transmission planning in their regions and, in principle, across ISO/RTO boundaries. While FERC has introduced a set of targeted incentives to encourage more investment in transmission networks, transmission service price regulation still relies primarily on traditional COSR in a form that is antithetical to the goals of PBR.

There has been a tendency in the incentive regulation literature to characterize regulatory mechanisms as either/or choices. That is, regulated firms either are or are not subject to COSR or PBR. This is a false dichotomy as introducing PBR is not an either/or decision. Finally, the nature of the obligations being placed on electricity distribution and transmission companies in the U.S. have changed considerably, reflecting decarbonization policies, competition policies, and changes in the technologies used in all segments of the electric power sector. This has increased the administrative burdens on state regulatory agencies. The expectation that PBR mechanisms can reduce this burden, whether this is a reasonable assumption or not, has increased [regulatory agencies] interest in PBR mechanisms.

The primary conclusions of this paper are as follows. The design and application of PBR to electric distribution companies in the U.S. has been slow to make progress. However, the pace of change has picked up and PBR mechanisms of one kind or another are being adopted more rapidly by state regulators. It is important to view PBR applied to the distribution of electricity as being composed of a set of "building blocks" that can be applied individually or combined to create a comprehensive PBR plan. These building blocks are often adopted sequentially as regulators become more comfortable with PBR mechanisms. U.S. regulators have now learned that the phrase "PBR" does not necessarily imply a simple forever dynamic price cap mechanism. Rather, a dynamic price cap mechanism is one component of a comprehensive PBR mechanism. With uncertainty, asymmetric information, moral hazard, rent extraction goals, budget balance constraints, etc., a simple forever price cap mechanism for electric distribution and transmission companies is optimal only under a very stringent and implausible set of assumptions. These considerations naturally lead to ratchets, performance benchmarking, profit sharing mechanisms, menus of contracts, quality incentives, and targeted incentives consistent with the broader set of policy goals beyond prices and costs.

Overall, the expansion of PBR has been gradual for a number of reasons. These reasons include the limited staff and budgetary resources available to state regulators and misunderstandings by U.S. policymakers of how so-called RPI-X mechanisms applied to electricity distribution and transmission evolved over time in Great Britain to be much more than a simple price cap mechanism.

The changes in the responsibilities of distribution companies in the last two decades have made PBR mechanisms more important and potentially more attractive, especially since the resources state commissions have at their disposal to manage frequent formal rate cases are limited. These changes have also made designing and applying good PBR plans more challenging. Resource limitations have also made it attractive for state regulatory commissions to learn from each other, to learn from other countries, especially Great Britain, and to rely on a variety of advisors and consultants for education and assistance. State regulatory agencies are now becoming more comfortable with PBR because the packages of PBR initiatives they are now seeing are better aligned with the regulatory challenges they face.

Finally, largely due to the decentralized and heterogeneous structure of the ownership of transmission companies and the reliance on non-profit system operators, there has been little effort to apply PBR mechanisms to the operating costs, investments costs, planning or other performance criteria for either transmission or system operations in the U.S. This is quite different from the experience in Great Britain where PBR, including the more recent RIIO framework, has been applied to transmission owners and the system operator for almost 25 years. The Federal Energy Regulatory Commission (FERC) has used a set of targeted incentives to stimulate investment in new transmission facilities, to create separate transmission companies, and to join ISO/RTOs. Initiatives to expand competitive opportunities for the development of new transmission facilities may be a partial substitute for PBR for transmission owners, but progress here has been slow. Nevertheless, there are a number of options for improving the regulation of transmission owners and system operates that require further evaluation, drawing on the now long experience in Great Britain and other countries.

—Summary by Trinity White

Paul L. Joskow (2024), "The Expansion of Incentive (Performance Based) Regulation of Electricity Distribution and Transmission in the United States", CEEPR WP-2024-01, MIT, January 2024.

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

Commentary.

FERC Order 2023: Will it Unplug the Bottleneck?

By: Les Armstrong, Alexa Canaan, Christopher R. Knittel, and Gilbert E. Metcalf

I. Introduction

A central element of any plan to get to a zero-carbon economy in the United States involves electrifying the personal transportation fleet and shifting much of the building stock to electric heating, hot water, and cooking. This idea is based on the idea that the United States can shift electricity production from fossil fuels to zero-carbon sources, including solar and wind. While fossil-fuel generated electricity production has historically vastly outweighed production from wind and solar, that is changing. Electricity production from coal exceeded that from wind and utility-scale solar by over 158 terawatt hours per month on average between 2001 and 2010. Between 2011 and 2020, the production advantage of coal over wind and solar declined to under 88 terawatt hours per month and has declined further since 2020. Electricity production from wind and utility-scale solar exceeded that from coal for the first time in April 2022 as it also did during February through May 2023 (EIA Electricity Data Browser).

Greening the grid will require major new investments in wind and solar. Bistline, Mehrotra, and Wolfram (2023) estimate that average annual low-carbon capacity additions will increase from 27 GW per year to 51 GW per year due to the Inflation Reduction Act. Other studies, such as Jenkins et al. (2022) estimate additions will be even larger (Figure 1). However, there is a significant waiting list for connecting new generation projects to the electrical grid. The number of applications has exploded since 2010, such that there are over 3000 projects in the various interconnection queues as of 2021 (Figure 2). Meanwhile, the median number of months to sign an interconnection agreement is nearly three years across all regions and projects, with significantly higher wait times in certain regions (e.g., MISO) and for certain fuels (e.g., solar and wind). The median time from interconnection request to commercial operation hit five years for projects completed in 2022, with wait times even longer for wind and solar, according to Rand et al. (2023).

In response to this growing interconnection bottleneck, FERC released Order 2023, titled "Improvements to Generation Interconnection Procedures and Agreements," on July 28, 2023. The 1481-page order (including concurring opinions and appendices) sets out several changes to the interconnection process to reduce cost uncertainty and length of time in the queue. This policy brief explores the interconnection

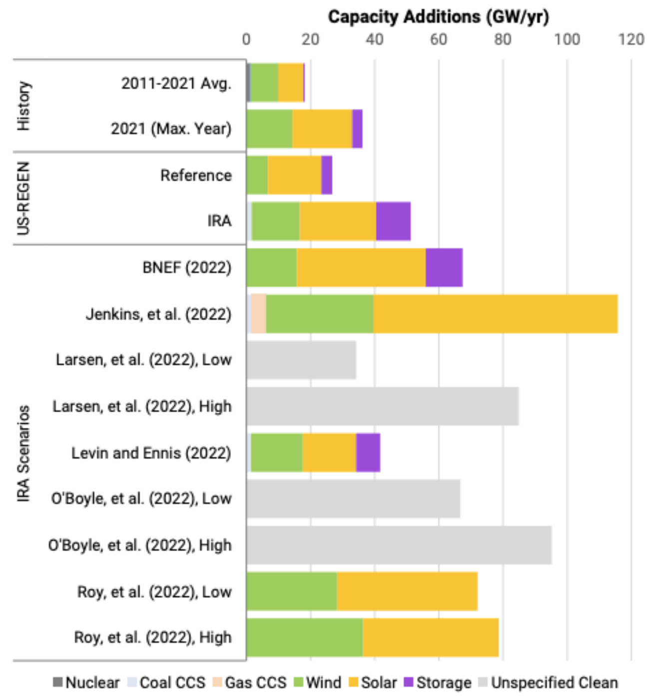


Figure 1. IRA Driven Capacity Addition Projections
Source: Bistline, Mehrota, and Wolfram (2023)

queue bottleneck and the various reasons for the bottleneck. It then examines FERC Order 2023 and asks whether it will make a meaningful difference in the interconnection queue bottleneck.

We conclude that FERC Order 2023 is a good first step towards addressing the problems that have arisen over the past two decades. It should reduce cost uncertainty to some extent and also reduce the number of speculative projects. Questions remain, however. Given the public good nature of interconnection and grid investments, how should the costs of network upgrades be shared among all grid users (on both the supply and demand side of the grid)? The current practice of shouldering all the costs on new generators connecting to the grid cannot be optimal. How can the interconnection process be made more of a forward-looking and proactive process that starts from a premise of achieving certain long-run goals of stability, reliability, while moving the United States on a path to a zero-carbon grid? Related to that question is the question of how best to link transmission planning with the process of connecting new projects to the grid?

II. Background

In 2003, FERC issued the initial interconnection policy, Order 2003, establishing procedures for connecting large generation facilities (200 MW and larger) to the transmission grid. The purpose of the order was to standardize the interconnection process, reduce planning uncertainty, and reduce delays for new projects. It was also designed to level the playing field between vertically integrated firms and merchant projects.

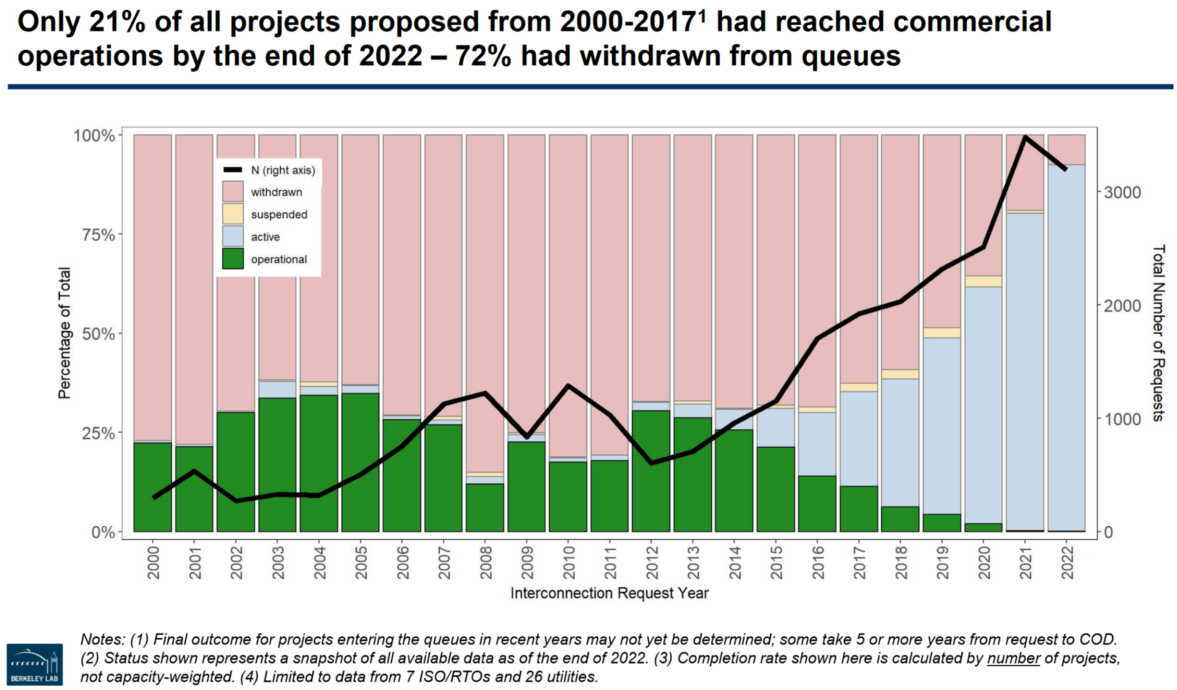


Figure 2. Interconnection Queue Status
Source: Rand, et al. (2023)

Due to transmission grid congestion, the introduction of a new generating facility to the grid can have unforeseen consequences for existing generators on the grid, depending on load characteristics. As a result, transmission providers require a series of studies before allowing a new facility to interconnect to the grid to ensure stability. FERC Order 2003 assigned all costs of network upgrades arising from the proposed project to the first project that triggered required network upgrades. The required upgrades and consequent costs were based on both the existing transmission grid and set of grid-connected facilities as well as on the anticipated grid-connected facilities earlier in the queue than the current project. Upstream departures from the queue could trigger changes to the assigned network upgrade costs, changes that could go up or down. As projects proceed through the various study processes (Feasibility, System Impact, and Facilities Studies), costs can dramatically change.

A complicating factor for predicting the ultimate network upgrade costs that will be borne by a particular project is the incentives due to the "first-come, first-served" nature of Order 2003 for submitting similar projects with different locations and/or queue submission dates. Modest changes in location or position in the queue can lead to significant changes in the assigned network upgrade costs that are difficult to predict for developers, given the obscure nature of these studies. Entering multiple projects in the queue, even when the developer only plans to construct one project, creates option value as the project with the lowest assigned costs can be kept while others are eventually withdrawn from the queue at low cost. This has been long understood (see, e.g., Gergen et al., 2008). Queue squatting with ghost projects is a way to insure against unexpectedly high network upgrade costs but leads to longer queues and greater uncertainty for all other projects around their ultimate assigned costs.

The first-come, first-served approach with generators paying most (if not all) network upgrade costs has been especially problematic for renewable projects, which, among other things, are more geographically constrained than fossil fuel projects. See, for example, the analysis by Alagappan et al. (2011) that compares 14 markets in the United States, Canada, and Europe. Analysis by Lawrence Berkeley Labs finds that the average time from interconnection request to commercial operation tends to be the longest for solar and wind projects (Rand et al., 2023, slide 32).

Johnston et al. (2023) do a detailed analysis of data from PJM. They find that interconnection costs, on average, are higher for renewable projects. They also identify important externalities across projects. As the queue size increases, study times increase. This is a classic negative congestion externality leading to too much entry. Second, interconnection costs tend to be lower when locating near projects that recently connected and incurred network upgrade costs. This suggests a positive timing externality as later entrants draft behind earlier entrants.

The existing literature indicates clear problems with queuing from the first-come, first-served approach taken by FERC Order 2003, along with the approach of allocating all network upgrade costs to the specific project triggering upgrades. The latter is particularly problematic since added upgrade costs to the project have risen from under 10 percent typically to as much as 50 to 100 percent of project costs, according to a report from the Americans for a Clean Energy Grid (2021). The ACEG also argues that network upgrades contribute to a more resilient grid, so placing all these costs on an interconnecting generator violates FERC's "beneficiary pays" principle (ACEG, 2021, p. 12).

FERC has recognized that network upgrade cost uncertainty creates perverse incentives for project developers. FERC writes, "We find that, absent reforms to require transmission providers to provide additional interconnection information, which can be used by interconnection customers prior to submitting an interconnection request, speculative interconnection requests will likely remain at current levels and continue to contribute to interconnection study delays and add costs to the interconnection process." (FERC Order 2023, para 67). The piecemeal response to the deficiencies of FERC Order 2003 has long led to calls for a response from FERC. FERC Order 2023 is that response.

III. FERC Order 2023

In response to the various problems identified with the interconnection process under FERC Order 2003, FERC released Order 2023 in July 2023. Citing significant changes in the electricity sector since FERC Orders 2003 and 2006, FERC noted that:

> The growth of new resources seeking to interconnect to the transmission system and the differing characteristics of those resources have created new challenges for the generator interconnection process. These new challenges are creating large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system, increasing costs for consumers. Backlogs in the generator interconnection process, in turn, can create reliability issues as needed new generating facilities are unable to come online in an efficient and timely manner.
>
> FERC Order 2023, Paragraph 3

While there are numerous elements in the nearly 1500-page order, reforms fall into three broad categories:

1. Reforms to implement a first-ready, first-served cluster study process;
2. Reforms to increase the speed of interconnection queue processing; and
3. Reforms to incorporate technological advancements into the interconnection process.

Many of these reforms take best practices from the more forward-thinking and proactive ISO/RTOs such as MISO, CAISO, and ERCOT, which are rich in wind and solar resources and were therefore incentivized to innovate in their interconnection approach sooner. They, too, however, are still encountering varying degrees of challenges in managing their queues.

A. First-Ready, First-Served Cluster Study

FERC Order 2023 calls for interconnection procedures to adopt cluster studies as the default method of studying interconnection costs. By clustering applications within specific windows (FERC set a 45-calendar day window during which requests could be made), all applications within that window would be treated as having been received at the same time. The cluster approach, FERC argued, "will minimize delays that arise from proposed generating facility interdependencies under the existing serial study process, in which lower-queued interconnection customers can strategically and monetarily benefit from network upgrades and associated costs borne earlier in the interconnection process by higher-queued interconnection customers." (para. 177) FERC left open how transmission providers create clusters. The order also included a number of proposals that would reduce the number of restudies and reduce cost uncertainty for applicants. It also included a requirement that transmission providers post metrics for cluster study processing time. Presumably, doing so will encourage the timely processing of the cluster studies.

Although a meaningful improvement, cluster studies still do not tackle significant issues that arise in the study process. CAISO, for example, implemented the cluster approach in the mid-2000s but still struggles with consequential queue backlogs. In 2021, CAISO received three times the amount of typical requests in what was then dubbed a "super-cluster." The lack of transparency in the study process still incentivizes developers to submit multiple projects without a clear understanding of what the ultimate upgrade costs will be. When the studies' results are returned, and the upgrade costs are too high for developers, they drop out, leading to a massive exodus of projects from the study and rendering the original cluster study of little use, necessitating a re-study. This, in turn, leads to longer queues, more costly studies, and an overall clogging of the queue.

In an attempt to address the transparency issue, FERC took note of one of MISO's successful policies to improve information access. As part of the cluster study process, the order requires transmission providers to provide "heatmaps," supplying information about impacts at the node-




Les Armstrong, Alexa Canaan, Christopher R. Knittel, and Gilbert E. Metcalf (2023), "Research Commentary: FERC Order 2023: Will it Unplug the Bottleneck?", CEEPR RC-2023-06, MIT, December 2023.
For references cited in this story, full bibliographical information can be found in the Working Paper.

level of existing and queued generation impacts that can be useful to prospective interconnection customers in subsequent applications. The heatmap would help prospective developers identify available interconnection capacity and points of congestion at particular sites that would likely trigger network upgrades or possible curtailments from potential future generators. This would help prospective developers avoid congested sites, although upgrades to the transmission system would eventually become inevitable.

With the requirement for a cluster approach comes a need to allocate network upgrade costs within the cluster. The FERC order allocates them on a "proportional impact method," which, according to the order, means "a technical analysis conducted by Transmission Provider to determine the degree to which each Generating Facility in the Cluster Study contributes to the need for a specific System Network Upgrade" (footnote 914). This should hopefully ameliorate the issue of ghost projects, giving a greater sense of what the queues look like and allowing for more effective policy in the future.

FERC is also increasing the pressure on speculative project submissions from developers. Upon entry into a cluster, prospective generating facilities now must make an initial study deposit between $55,000 and $250,000 (depending on the size of project). They must also meet stringent site control requirements, "thereby reducing the negative impacts of speculative interconnection requests" (para. 583).

In addition, a further effort to address speculative projects and to reflect the negative externalities imposed on other projects in a cluster when a project withdraws from the queue, the order imposes withdrawal penalties that increase the further along in the study process the project is. Withdrawals at the initial cluster study incur a penalty of twice the study costs. If withdrawal occurs further along, the penalty rises to as much as 20 percent of network upgrade costs. Penalties are not imposed if the withdrawal does not have a material impact on costs or timing on projects with an equal or lower queue position. Nor are penalties imposed if there are significant, unanticipated increases in network upgrade cost estimates during the study process.

B. Increase the Speed of Interconnection Queue Processing

The order made two substantive changes to cut down on the time projects spend in the interconnection queue. First, it eliminated the "reasonable efforts" standard for carrying out the various interconnection studies and, at the same time, created financial penalties on transmission providers for failing to meet requisite interconnection study deadlines. This recognizes the fact that transmission providers historically had been missing deadlines for completing studies while facing no consequences for doing so. Penalties for delayed studies now range from $1,000 per day for cluster studies to $2,500 per day for facilities studies beyond tariff-specified deadlines (in all cases subject to overall caps on penalties).

Second, it standardized the study process for affected systems. Noting that the current LGIP "lacks consistency between transmission providers" (para. 1026), the order set forth a series of requirements, including study scope, timelines, and penalties for failure to meet deadlines. The standardization will allow for greater transparency and information and resource sharing between RTOs/ISOs.

C. Incorporate Technological Advancements Into the Interconnection Process

The third set of issues involved were measures to incorporate technological advancements that create some flexibility in the interconnection process. First, it allowed multiple generating facilities to co-locate on a shared site behind a single interconnection request, thereby addressing what FERC perceived to be a potential barrier to entry by "necessitat[ing] a case-by-case approach that the Commission cautioned against in Order No. 2003" for co-located facilities. FERC argued in the final order that the adding greater clarity around co-location would facilitate greater competition. The Commission argued that this reform would "create a minimum standard that would remove barriers for co-located resources by creating a standardized procedure for these types of configurations to enable them to access the transmission system" (para. 1325).

Next, it required transmission providers to evaluate requests to add generating facilities to an existing interconnection request prior to deeming the addition a material modification so long as the request is done in a timely fashion and does not affect the requested interconnection service level. Material modifications involve significant additional costs to a generating facility, so this removes unnecessary costs when the request is unlikely to affect network upgrade costs.

Additional changes under the order provide various degrees of flexibility, including the ability to access surplus interconnection service of existing customers and use assumptions in studies that reflect the proposed charging behavior of storage resources. This might, for example, cover requirements about charging behavior during peak load conditions.

IV. Assessment of the Order

The shifts to cluster studies and a first-come, first-ready approach are impactful and should serve to reduce the number of speculative projects that contribute to clogging the interconnection queue. More substantial withdrawal penalties will also help. It should be noted once again that many of the reforms included in FERC Order 2023 have already been put into effect by a number of transmission providers, including cluster study reforms, changes to first-come, first-served, cluster study cost allocation, and enhanced financial or readiness commitments. Cluster studies, for example, are already required in a number of RTOs/ISOs, including CAISO, NYISO, and MISO, among others (Bartlett et al., 2023). Queue data from the Lawrence Berkeley National Laboratory does not show that waiting time in the interconnection queue has fallen significantly (or even appreciably) with these reforms.

But there are other unaddressed problems. The first is that network upgrades resulting from new generation facilities added to the grid add to the resiliency and flexibility of the grid. Given that, having the generation facilities that prompt the network upgrades pay the entire cost of upgrades violates FERC's "beneficiary pays" principle and likely leads to too little investment. Socializing some of these costs to all transmission grid users is a policy meriting greater consideration and is likely to be an important incentive for adding new zero-carbon generation to the grid and so contribute to national plans to green the electrical grid dramatically.

The second relates to one of the core issues with the current interconnection paradigm: These procedures were created during and for an era dominated by fairly location agnostic and dispatchable fossil fuels. All the rules and regulations were created in consideration of the physical attributes of these generators, which are noticeably distinct when compared to geographically constrained renewable generator projects. Nothing in the order moves us closer to a fully forward-looking, rational grid planning process where we consider from a system-wide perspective where new generation should be sited and what additions to the transmission grid will support new renewable generation that is clogging up the queue.

Examples of these more forward-looking approaches can be observed in Texas and Europe. In Texas, the Legislature established the Competitive Renewable Energy Zones (CREZ) in 2005, which established priority areas for utility-scale wind development in the North-Western Permian Basin. The legislation included transmission planning and construction where the costs were socialized by ratepayers. The policy successfully resulted in 3,600 miles of high-voltage transmission lines, comprising 23% of US additions in the past 12 years. It also facilitated 23 GW of wind generation, which is 56% of the state's total wind capacity, the highest in the nation (Jankovska & Cohn, 2020). In Europe, central planners identify high renewable resource regions, for example in the North Sea, and plan the transmission corridors as well as the interconnection processes. Once the planning is complete, RFPs are released to allow biddings from developers to compete on project proposals. This approach has led to a boom in offshore wind capacity.

In contrast, in the US as it is, we leave it to developers to decide where and when to site new projects and determine network upgrades without considering how changes to the transmission grid could be implemented to rationalize those grid additions. This piece-meal approach severely constrains our current strategy to reduce our emissions through electrifying transportation and the building sector with the hope that we will have a zero-carbon electricity system to power those sectors. In order to unlock the energy transition, more comprehensive reforms that enable a more centralized planning approach are needed.

As the ACEG (2021) has put it,

> FERC and RTOs should pursue planning reforms. Consumers would benefit from more efficient transmission at a scale that brings down the total delivered cost, rather than continuing the current cycle of incremental transmission built in the project-by-project or generator-only cost assignment regime. That shift will not happen in the current interconnection process. Instead, FERC should fundamentally reform the regional and inter-regional transmission planning process to require broader pro-active and multi-purpose transmission planning. (p. 6)

FERC Commissioner Allison Clements puts it even more dramatically in her concurrence with the 2023 order:

> [W]hile this rule can be expected to improve matters, more will be necessary to solve the problem. What was perhaps considered a straightforward kitchen renovation has become more complicated. After we have removed the cabinets and taken out the drywall, we have discovered outdated wires, rusted pipes and cracks in the foundation. None of these additional challenges are insurmountable, but they are in some ways more fundamental to getting that modern, working kitchen up and running.
>
> Clements (2023), p. 3

She argues for further work that links the interconnection process to proactive transmission planning. She cites promising developments in SPP, MISO, and CAISO. However, those initiatives are in the early stages, and there is a lack of comprehensive and nationally cohesive planning of a sort that FERC could lead on.

Second, she sees potential promise in a system that links interconnection processes with competitive resource solicitations, with the latter ensuring scarce interconnections are allocated in an efficient manner. Finally, she argues for the consideration of a more “focused” interconnection approach that limits restudies. While this is not a panacea and raises important questions, streamlining the process and reducing restudies (and consequent cost changes) seems valuable. Her suggestion is echoed in a report by Norris (2023), who advocates for a focused approach ala Clements or a connect and manage approach as is carried out by ERCOT and in the UK. Key to this approach is a greater willingness to utilize curtailments in an energy-only market to manage the grid rather than an exhaustive interconnection study process that tries to avoid grid congestion issues where curtailment might be necessary. As Norris puts it, “The overall trade-off for generators is the ability to interconnect much more quickly with fewer network upgrades in exchange for bearing more curtailment risk and not receiving capacity compensation.” (p. 4) Whether this is a trade-off that generators and grid customers would tolerate outside of Texas is unclear.

While our focus is specifically on FERC Order 2023, it is clear that a more efficient and streamlined interconnection process and build-out of the national transmission grid will require coordination among government regulators, transmission providers, interconnection customers, and the research community to develop and implement improved data collection, modeling, and interconnection procedures, as well as workforce development to ensure there are sufficient numbers of trained engineers with policy expertise required to address interconnection demands.

The order also does not address how it will tie into other FERC Orders, like Order 2222 which incorporates distributed energy resources (DERs) into the wholesale markets. Order 2222 has yet to be fully implemented by transmission providers as most are struggling to incorporate the proper technology and transparency required of the order. However, it is important to note that the full implementation of this order could potentially lessen the strain on the transmission system. Coupling these orders together would help in the technology development process to make technology that can address the needs of both orders at the same time, making technology that can actually work together. Not only that but coordinating both orders more tactfully together could allow for a greater understanding of what the grid will look like in 10 years' time. The interconnection queue with DERs and a cleaner queue will lead to new needs and policies that will need to be written. Not incorporating these policies together with future-focused measures will require more work in the near term.

V. Summary

The long delays in the various ISO and RTO interconnection queues stand as a significant impediment to the transformation of the US electrical system to a zero-carbon grid. The process established over twenty years ago was designed for a fossil-fuel generation fleet that was locationally flexible. Wind and solar projects are more geographically constrained and the interconnection process is not well-designed to integrate these constrained resources into the grid. At the same time, the cost allocation process established in FERC Order 2003 contributes to significant cost uncertainty, which has led to gaming the system through the use of multiple speculative projects in an effort to minimize network cost upgrades assigned to developers by transmission providers. This, in turn, contributes to further clogging the queue and adding to delays and costs.

FERC Order 2023 is a good first step towards addressing the problems that have arisen over the past two decades. It should reduce cost uncertainty to some extent and also reduce the number of speculative projects. Questions remain, however. Given the public good nature of interconnection and grid investments, how should the costs of network upgrades be shared among all grid users (on both the supply and demand side of the grid)? The current practice of shouldering all the costs on new generators connecting to the grid cannot be optimal. How can the interconnection process be made more of a forward-looking and proactive process that starts from a premise of achieving certain long-run goals of stability and reliability, while moving the United States on a path to a zero-carbon grid? Related to that question is the question of how best to link transmission planning with the process of connecting new projects to the grid?

Historically, FERC has taken a siloed approach in its orders with little coordination between transmission planning and the interconnection process. We can only hope that FERC takes up the challenge put forward by Commissioner Clements in her concurrence with FERC Order 2023 to take a more coordinated and comprehensive approach to planning to address the challenges we face as we modernize and decarbonize our electrical system.

Research.

Designing Distribution Network Tariffs Under Increased Residential End-user Electrification: Can the US Learn Something from Europe?

By: Graham Turk, Tim Schittekatte, Pablo Dueñas Martínez, Paul L. Joskow, and Richard Schmalensee

In almost all US states, electric utilities have been recovering distribution costs, along with electricity supply costs, from residential and small commercial customers based on monthly electricity consumption (in kWh), regardless of the timing of that consumption. We refer to these as flat volumetric tariffs. As there is broad consensus that flat volumetric network tariffs are not cost-reflective (Pérez-Arriaga et al., 2017) and discourage electrification (Schittekatte et al., 2023), regulatory commissions across the US have taken a range of approaches to designing alternative tariffs. Recently, an increasing number of states have enacted policies to make time-of-use (TOU) rates the default option (Kavulla, 2023). In all these states there is no retail competition, so the distribution utility is also the energy supplier, and the TOU rate bundles supply, distribution, and transmission costs.

This evolution is a step in the right direction; TOU rates, when well designed, can provide end users with relatively good incentives to shift load from periods with high to low marginal supply costs at the bulk power system level (Schittekatte et al., 2024). However, when local concentrations of EVs (or other shiftable load) rise and wholesale price patterns are poorly aligned with demands on distribution networks, TOU rates may increase network congestion. A per-kWh charge alone, even a time-differentiated one, provides no disincentive for consumers to limit their maximum instantaneous kW consumption. As consumers defer EV charging to off-peak hours, TOU rates may result in local demand spikes at the onset of off-peak periods, potentially leading to steeply rising costs for distribution network upgrades.

Figure 1 illustrates this issue, showing average hourly electricity demand for a simulated neighborhood in which 30% of households have EVs and seek to minimize charging costs. The left panel shows the aggregated load under flat volumetric tariffs, which are most common today. The right panel shows the same under a bundled TOU rate, with the off-peak period beginning at 9:00 PM. Under the status quo, the local peak increases due to EV adoption; vehicles begin charging immediately upon arriving home but heterogeneity in arrival time leads to some spreading of charging over the evening hours. Under the bundled TOU rate, all vehicles that arrive home prior to 9:00 PM delay charging to start until that hour (when the electricity cost is cheaper), producing a large demand increase at the onset of the off-peak period.

We find under bundled TOU pricing, this correlated EV charging becomes a serious issue even at low EV adoption levels, with newly created local demand peaks appearing as early as 15% adoption. This is even more concerning when considering that EV adoption is highly clustered spatially and will not proceed uniformly across a distribution utility's service territory.

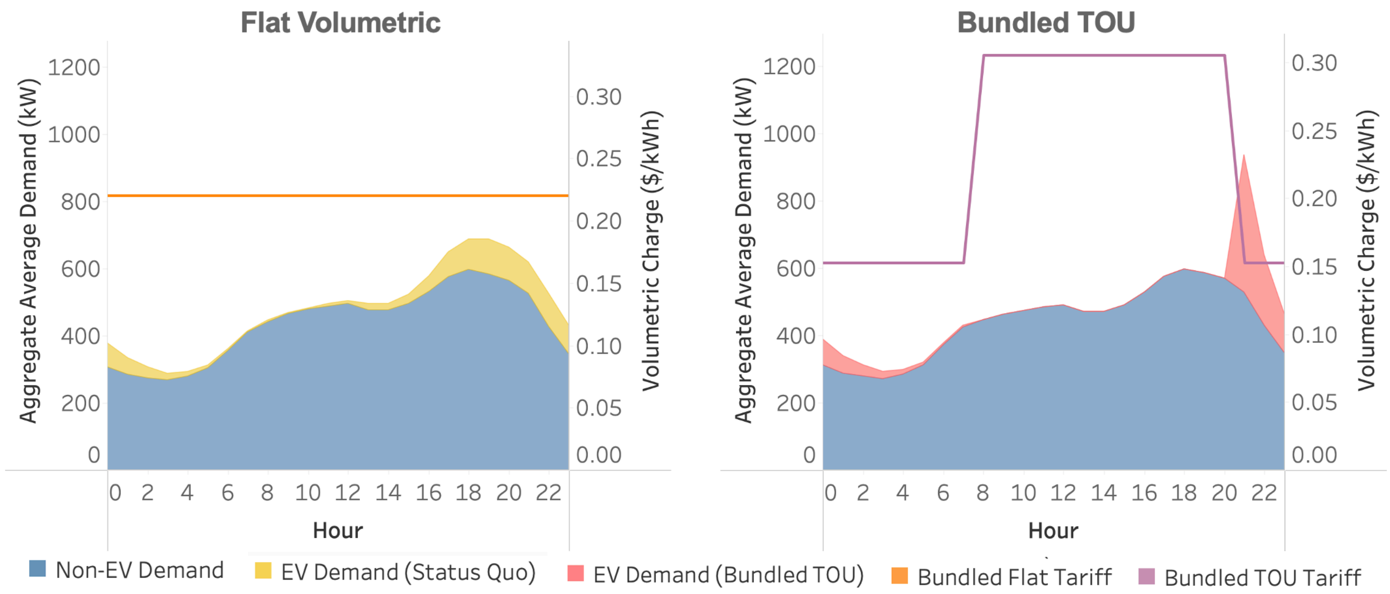


Figure 1. Average hourly weekday electricity demand aggregated across 400 households with 30% EV adoption under a flat volumetric tariff (left) and bundled TOU tariff (right)

Under the flat volumetric tariff, EVs start charging immediately upon arrival. Under the bundled TOU tariff, EVs delay charging until the start of the off-peak period at 9:00 PM.

In this paper, we study how to complement TOU supply charges with separate distribution network tariffs to deal with the problem of bunched EV charging. To perform the analysis, we conduct a realistic case study using simulated residential load and driving profiles at increasing levels of EV adoption, calibrated for 400 households in Massachusetts. We study three types of network tariffs—fixed (per-connection), volumetric (per-kWh), and capacity (per-kW)—and analyze the results of households individually minimizing their electricity costs. All network tariffs are paired with a 2-part TOU supply tariff. We introduce two types of per-kW charges that have been in place for residential consumers in several European countries for many years. First, demand charges for which the maximum (ex-post) measured peak demand during a predefined time period determines the network charge. Second, subscription charges for which end users contract ex-ante for a maximum per-kW level they want to have access to at all times during a predefined time period. We run two scenarios (low and high) representing a range of possible network upgrade costs and consider three key metrics to compare the performance of the different network tariffs: annual local peak demand (which drives network investments), levelized cost of EV charging, and changes in network charges for non-EV households. The paper includes a review of network tariffs prevalent in Europe and both default TOU and EV-specific tariffs active in the US. We also review the academic literature on network tariff design in the face of increasing consumer adoption of distributed energy resources.

Figure 2 shows the simulated neighborhood's annual peak demand under all networks tariff tested at 5% EV adoption increments. The right panel zooms in on 0 – 30% EV adoption to highlight the divergence in tariff performance even at low adoption levels. The fixed, 1-part per-kWh and 2-part TOU per-kWh tariffs produce the same annual peak result because the network tariff does not impact the shifting incentives from the common TOU supply charge (the 2-part TOU per-kWh network tariff has the same on/off-peak structure as the 2-part TOU supply charge).

A capacity tariff outperforms fixed and volumetric tariffs in terms of annual peak because it provides an incentive to charge at a level lower than the charging equipment's technical potential, illustrated in Figure 3. The left panel shows the demand profile of an individual household during one 24-hour period under a bundled TOU tariff compared to under a subscription network tariff where the household manages EV charging to stay below its contracted capacity of 3.0 kW. Even without centralized control, when all households behave like this, acting independently to manage their own demand, the result is a lower aggregate peak compared to a bundled TOU rate, shown in the right panel.

Table 1 shows the results of the three metrics for the different network tariffs under 50% EV adoption. Per-kWh network charges lead to high EV charging costs and lack a price signal to limit aggregated demand peaks (hence increasing the total network costs to be recovered). Fixed network charges foster electrification by lowering the cost of EV charging, yet they shift costs from EV owners to others and again lack a mechanism to mitigate peak demand. Capacity-based tariffs (demand and subscription charges) offer a compromise, providing a significant reduction in levelized charging cost compared to per-kWh tariffs while increasing network costs for non-EV owners by only a modest amount compared to a situation without EV adoption. These network tariffs, complementing TOU supply charges, are a pragmatic approach to better control the impacts of rising EV penetration on network costs; incentivizing electrification (a priority for many US states) need not be pursued at the expense of broader affordability goals.

While a 3-part seasonal demand charge achieves the lowest annual peak (and associated distribution network costs) in our case study,

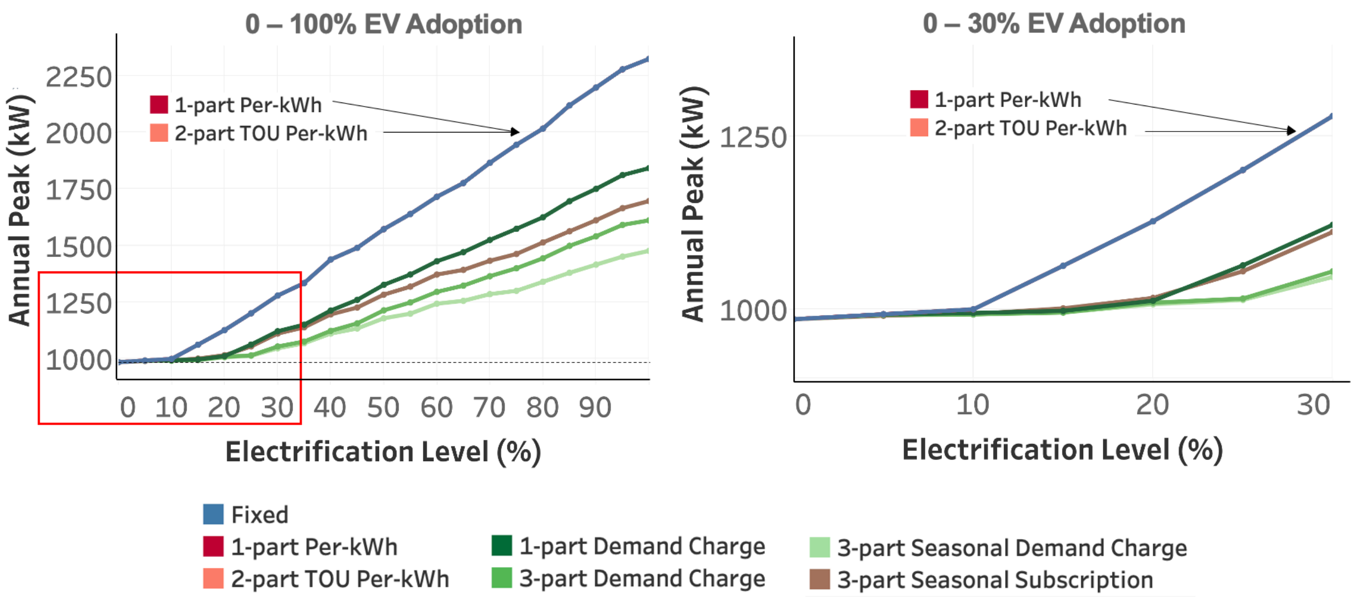


Figure 2. Annual peak demand at 5% EV adoption increments for seven network tariffs tested (left), with 0 – 30% adoption magnified (right)

As early as 15% adoption, fixed and per-kWh tariffs diverge sharply from capacity-based tariffs, which incentivize households to spread out charging demand.

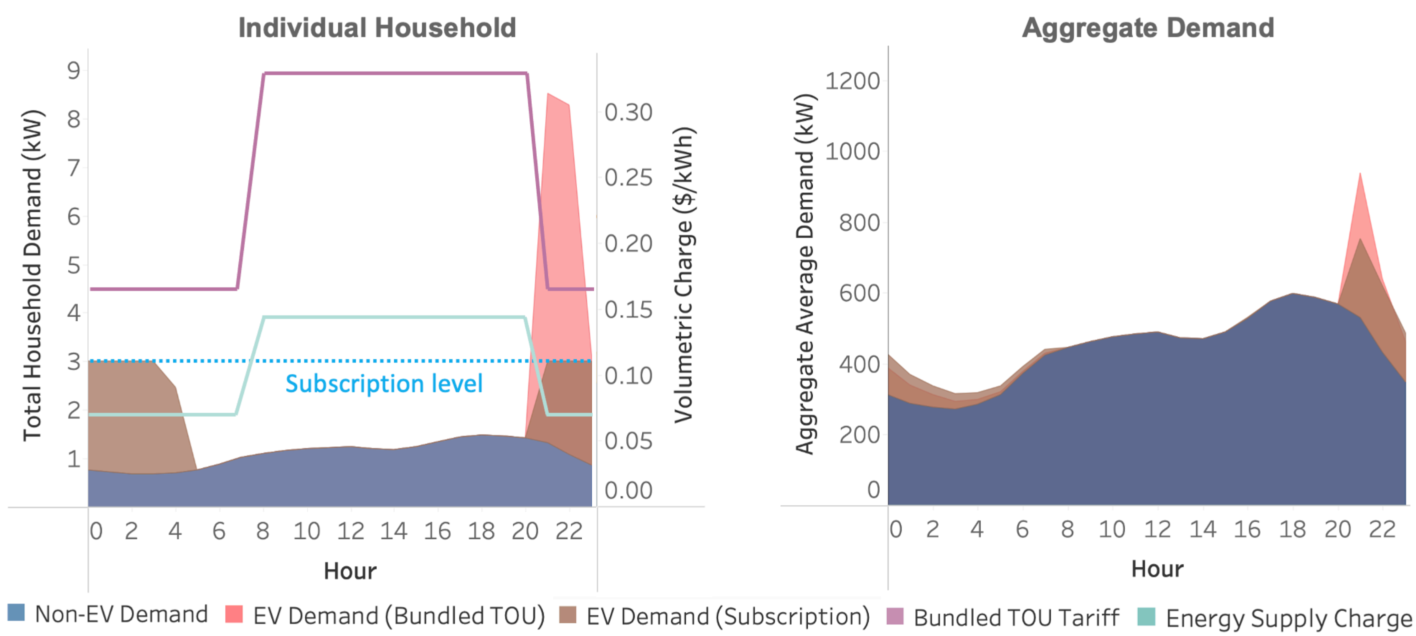


Figure 3. The impact of a subscription tariff.

Example of an individual household reacting to a subscription tariff versus a bundled TOU tariff (left) and average hourly weekday electricity demand aggregated across all 400 households for the subscription tariff versus bunded TOU tariff at 30% EV adoption (right). Note that the scales for the vertical demand axes are not equal. Under a subscription tariff, households still delay charging until the start energy off-peak period, but the peak is less pronounced because households have an incentive to manage charging to stay below their contracted capacity.

Network Tariff	Annual Peak (kW)		Levelized Charging Cost ($/kWh)		Change in Network Cost for non-EV owners (%)	
LRMC	$50/kW	$150/kW	$50/kW	$150/kW	$50/kW	$150/kW
Fixed	1572		$0.07	$0.07	63%	84%
1-part Per-kWh	1572		$0.18	$0.19	-8%	3%
2-part TOU Per-kWh	1572		$0.15	$0.16	-4%	8%
1-part Demand Charge	1326		$0.08	$0.08	12%	20%
3-part Demand Charge	1213		$0.07	$0.07	10%	16%
3-part Seasonal Demand Charge	1178		$0.07	$0.07	8%	12%
3-part Seasonal Subscription	1283		$0.10	$0.10	13%	20%

Table 1. Key metrics for each network tariff at 50% EV adoption under low and high network upgrade cost scenarios (i.e., LRMC)

There is a tradeoff among assessment criteria; the fixed tariff performs best in levelized charging cost but shifts costs to non-EV owners. Per-kWh network tariffs protect non-EV owners but increase charging costs. Capacity-based tariffs offer a compromise.

such a rate design is difficult to explain to customers and does not provide protections against bill shocks. In contrast, a subscription charge performs reasonably well for all considered assessment criteria. As Public Utility Commissions attempt to balance stakeholder interests in promoting electrification, a tariff design that does not create big winners or losers may be the most palatable. And whereas some tariff designs rely on perfectly rational consumer behavior to achieve their desired impact, we show in the paper how a subscription charge's performance on all criteria actually improves when a small portion of customers ignore price signals. Further we argue that subscription tariffs have several implementation advantages.

First, if a customer must subscribe in advance and is required to resubscribe from time to time—e.g., with estimated savings and a default option to continue at the same level—it forces them to think about how they can minimize costs. When the demand charge just gets buried in the tariff, they may not focus their attention on minimizing total cost. In contrast, under a subscription charge smart meters are typically programmed such that the meter is temporarily disconnected if instantaneous demand exceeds the subscribed level. This immediate feedback will help coach customers to not turn on multiple high-power devices simultaneously or to purchase devices that make it possible to program which appliances get turned off first (Mou et al., 2017). Second, a subscription offers more bill certainty, which is important for customers on tight monthly budgets. Even without perfect foresight, customers can better predict their costs using their subscribed value compared with a demand charge charged after the fact. Third, a subscription structure is similar to popular phone and internet plans, whereby customers pay for a maximum level of service that cannot be exceeded without incurring penalties. A familiarity with these types of plans will help explain the logic of subscription charges and ease the transition to new network tariffs. Fourth and last, customers signing up for certain levels of maximum demand to which they want to have access better aligns the horizon of consumer decisions with the horizon of network planning, i.e., subscription plans can help utilities to plan future networks.

In summary, our results urge utilities and their regulators to consider the importance of separating network charges from TOU supply charges and implementing a subscription network tariff. This recommendation is not exclusive to states with vertically integrated utilities but can equally be applied to states with unbundled tariffs (e.g. the three California IOUs) or retail competition. In the latter cases, while the separation between energy and network costs is inherent to the regulatory model, currently often flat or TOU per-kWh tariffs are in place to recoup distribution costs. A well-designed subscription tariff has the potential to 1) mitigate the need for local capacity upgrades, especially at early adoption levels, 2) provide low levelized charging costs for EV owners, a key motivator for EV adoption, and 3) reduce the cost burden on non-EV households.

Graham Turk, Tim Schittekatte, Pablo Dueñas Martínez, Paul L. Joskow and Richard Schmalensee (2024), "Designing Distribution Network Tariffs Under Increased Residential End-user Electrification: Can the US Learn Something from Europe?", CEEPR WP-2024-02, MIT, January 2024.
For references cited in this story, full bibliographical information can be found in the Working Paper.

Joe DeLosa III, Johannes P. Pfeifenberger, and Paul L. Joskow (2024), "Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.", CEEPR WP-2024-03, MIT, February 2024.



Research.

Regulation of Access, Pricing, and Planning of High Voltage Transmission in the U.S.

By: Joe DeLosa III, Johannes P. Pfeifenberger, and Paul L. Joskow

We focus on the regulation of the transmission system by the Federal Energy Regulatory Commission (FERC) in the context of modern wholesale markets, the creation of Independent System Operators ("ISOs") and Regional Transmission Operators ("RTOs"), and the transition to a low-carbon or no-carbon electric power sector. The transmission system plays a key role in supporting the economic and reliable supply of electricity to end-use or retail customers.

The transmission grid is composed of several different types of transmission facilities that support different "needs" for transmission capability. Large high-voltage regional transmission facilities are the 'highway' for electricity. Connected to this "bulk-power" grid are lower-voltage transmission facilities that provide the necessary on-ramps for smaller generation facilities as well as off-ramps to enable delivery of wholesale power to local distribution systems. Significant investments in transmission have occurred throughout the United States in the last decade, with annual capital expenditures by FERC-jurisdictional transmission owners of $20–25 billion since 2013.

The organization and regulation of the U.S. electric power sector has changed dramatically since its origins in the late 19th century but especially in the last 25 years. Historically, electric power systems are made up of three component parts: generation, transmission, and distribution, as shown in Figure 1. Large, utility-scale generators provide electric power by converting a fuel source, including the sun, wind, geothermal heat, nuclear fuel, run-of-river, or a wide array of fossil fuels, into electricity. Typically, this electricity is injected into the high-voltage transmission system, which is an interconnected network of power lines that transmits electricity over long distances within and between states. Finally, the distribution system receives this electricity from the transmission system and distributes it locally to end-use customers.

The first Public Utility Commissions ("PUCs"), or state regulatory agencies with jurisdiction over electric and gas utilities, were founded in 1907, laying the foundation for more than two-thirds of U.S. states creating PUCs by 1920. From 1907-1920 while subject to constitutional restrictions imposed by the Supreme Court, states retained a large degree of autonomy even in creating policies that impacted neighboring states. In 1935 congress passed the Federal Power Act

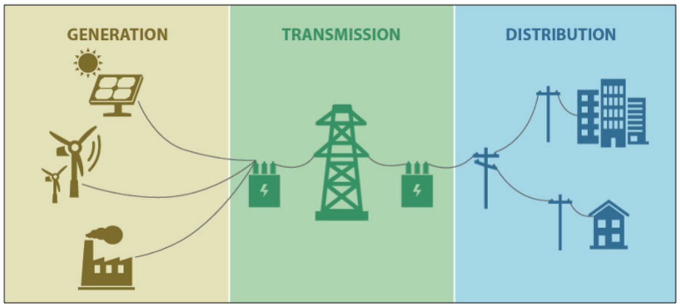


Figure 1. Electric Power System Overview
Source: Congressional Research Service, R45762 (August 4, 2022) at Figure 1.

("FPA") closing a gap in electricity regulation pertaining to matters remaining beyond the purview of state jurisdiction, and not yet covered by any federal law. The FPA placed under federal jurisdiction "the transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate commerce;" requiring that all rates under federal jurisdiction be "just and reasonable" and not unduly discriminatory or preferential. The FPA has since been subsequently amended but remains the main regulatory framework upon which the transmission regulations effective today were built.

Following the FPA's passage in 1935, federal jurisdiction expanded to include interstate transmission of electric energy. The remaining components, "generation" and "distribution," as well as intrastate transmission, remained within state jurisdiction. As a result, the dominant 20th century regulatory paradigm featured large, "vertically-integrated" utilities, regulated under state law with exclusive service areas and that typically owned all generation facilities sufficient to serve the retail customers within their geographic franchise areas or their "native" loads, and delivered the electricity largely through their own transmission and distribution networks. This framework largely resulted vertically-integrated utilities planning its own generation, transmission, and distribution facilities to serve the utility's "native load" customers—with only sales between utilities and third parties subject to federal jurisdiction.

This resulted in fairly limited federal involvement because only interstate transmissions of energy were regulated by the federal government through FERC; formerly the Federal Power Commission). It also is important to note that FERC jurisdiction over transmission and power markets does not extend to certain publicly owned power companies and federal power marketing agencies. FERC jurisdiction over transmission and electricity markets also does not apply to single-state power grids that are not synchronized with the interstate transmission network, such as the ERCOT managed grid covering most of Texas.

It was not until the 1990s, that some states sought to lower electricity rates by restructuring their utilities and creating organized competitive wholesale markets for electricity generation and related network support services. Some "restructuring" laws allowed retail customers, for the first time, to choose an energy supplier (i.e., of generation services) other than their incumbent utility company. In many states, these same laws simultaneously required utilities to "unbundle" their generation assets from their existing utility business, creating a series of competitive independent generators and retail suppliers from which distribution utilities and retail customers could choose to set the framework for wholesale power markets in response to state restructuring efforts of the 1990s, a series of landmark FERC orders overhauled the method of using, selling, and planning transmission facilities in the U.S. By applying the FPA's requirement of "non-discrimination" to the bulk transmission system, FERC set the foundation for the modern U.S. electricity industry, in which "open access" to the transmission system and lower-cost electric generation must be provided to all market participants, including competitive generators.

FERC issued Order 888 in 1996, the first of these landmark orders, just prior to the state restructuring reform efforts in the late 1990s. The order transitioned the industry into a new open-access transmission paradigm, and away from the prior industry practice where each transmission owner controlled the use and assignment of available transmission capacity. This new "open access" framework provided non-discriminatory transmission system access to all market participants, with the goal to eliminate the ability for local utilities to provide preferential treatment to their own generation resources and setting the stage for a rapid growth in interstate trading of electricity.

In January 2000, FERC issued the (aptly-named) Order 2000, setting out minimum characteristics and functions necessary for ISOs and RTOs. FERC promoted the creation of RTOs and ISOs to improve open access to the transmission grid envisioned through Order 888 and provide a framework and platform for newly deregulated utilities and generation companies to buy and sell electricity services in competitive wholesale power markets. FERC envisioned these RTOs/ISOs implementing organized wholesale power markets to replace the previous power pools of interconnected utilities that would rely solely on bilateral transactions.

Each ISO/RTO has a well-defined geographic service area which can cover one state (e.g., New York) or multiple states (e.g., New England). Throughout their service area, RTOs/ISOs are granted responsibility for ensuring grid reliability. RTOs/ISOs are further responsible for operating the regional spot markets for electric energy, managing transmission congestion, and identifying and procuring the necessary "ancillary services" that are required to maintain grid reliability and the ongoing matching of generation and load. Market monitors are tasked to ensure competitive outcomes and prevent manipulation of market prices or other types of fraud that would negatively impact electric ratepayers or other market participants. In addition to these market and operational functions, Order 2000 required RTOs/ISOs to take "ultimate responsibility" for transmission planning within their region.

Less than 10 years after the issuance of Order 2000, FERC issued Order 890 to further advance transmission reform. These reforms set the underlying standards for transmission expansion planning processes used by all FERC-jurisdictional utilities today. Notably, transmission planning processes were now required to include region-wide coordination, early opportunities for open stakeholder and customer engagement (including an opportunity to review the underlying assumptions relied on to plan transmission facilities), and a method of regionally allocating the costs of resulting transmission projects.

Less than five years following the issuance of Order 890, FERC sought to address identified shortcomings of regional RTO/ISO planning processes through the issuance of Order 1000. The order required affirmative participation of transmission providers in developing regional plans with the participation of stakeholders and select the most efficient solutions available to solve identified regional transmission needs—with the costs of these projects "allocated" to transmission customers throughout the planning region. To introduce competition in the identification and selection of transmission projects, FERC removed the long-held federal "right-of-first-refusal" by incumbent transmission owners, enabling competitive transmission developers to bid on regionally-cost-allocated transmission expansions in competition with incumbent transmission owners. Order 1000 also required that transmission plans address state and federal public policy needs.

The RTOs/ISOs have created and manage organized bid-based spot markets for wholesale power that integrates the management of transmission congestion with the determination of market clearing hourly day-ahead and real-time prices for energy. As a result, the organized wholesale energy markets in the U.S. lead to prices that may vary by location when there is congestion on the network. This system of location-specific pricing of electricity is called "nodal pricing" or Locational Marginal Pricing ("LMP") and forms the foundation for pricing electricity for all RTO/ISO markets in the U.S. Because higher LMPs are a direct result of insufficient transmission capacity, expanding transmission capacity to constrained areas will necessarily relieve the congestion, reduce wholesale LMPs, and make lower-cost generation accessible to customers. High observed or projected congestion costs on transmission paths between generation and load areas provides valuable information for transmission planning processes that are targeted to increase market efficiency and reduce total customer costs. Congestion costs observed in locational power markets are, however, an incomplete picture of transmission-related impacts on total electricity costs: they do not fully indicate the extent to which investment in additional transmission capacity can reduce wholesale power costs to balance supply and demand consistent with reliability goals, nor reflect public policy goals such as expanded supply of carbon-free generation while addressing resource adequacy and grid reliability challenges.

As required by FERC, transmission planning is supposed to address reliability, economic, and public policy needs. In most regions, this means that separate planning processes are used to: (1) address local reliability-driven transmission needs; (2) enable the reliable interconnection of new generators; (3) reliably enable requests for long-term transmission service; (4) address region-wide reliability needs; (5) improve market efficiency (i.e., economic congestion relief) so lower-cost resources can be used to serve customers; (6) to address state or federal public policy needs; and (7) contemplate interregional transmission projects. As shown in figure 2, this leads to a siloed set of planning processes that address these various needs incrementally rather than holistically and is inefficient.

A number of national transmission studies have found that doubling or tripling the available regional and interregional transmission could

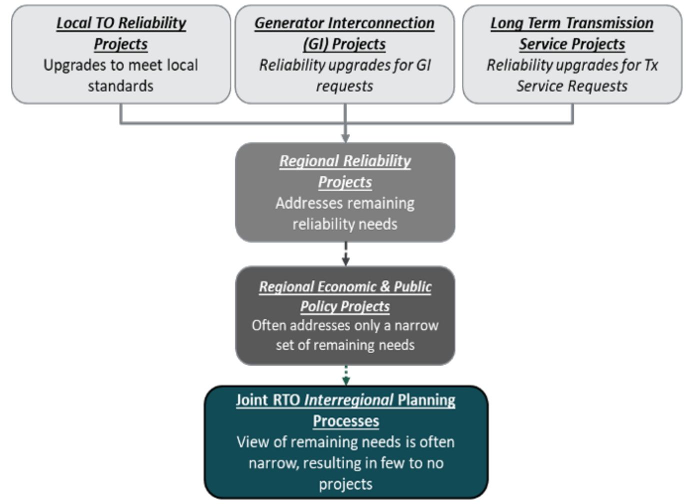


Figure 2. Typical U.S. Transmission Planning Process
Source: J. Pfeifenberger, The Benefits of Interregional Transmission: Grid Planning for the 21st Century (March 15, 2022) at 3 (with permission).

provide significant cost savings and reliability benefits, particularly as the grid transitions to carbon free resources like wind and solar at geographic locations different from the bulk of thermal generators. Expanding transmission nationally can also allow for the development of lower-cost carbon-free energy resources and delivering their output to load, diversity resource and load, increase system reliability and resilience, and offer a broader set of wholesale power market benefits. However, despite the net benefits of expanded interregional transmission demonstrated through these studies, they have failed to yield specific regional and interregional transmission expansion opportunities simply because the studies are misaligned with the transmission planning processes and geographic boundaries that are used by different ISO/RTOs.

Certain transmission upgrades are necessary to enable the connection of new generating resources. These interconnection facilities include the transmission facilities between the generator and the closest transmission line or substation on the existing grid, which is called the "Point of Interconnection" ("POI"). Facilities between the generator and the POI are typically constructed by the generation project developer. By interconnecting its facility, the generator is seeking to inject power on the existing grid facilities owned by the local TO and the regional grid operator. Upgrades to the local grid around the POI may be necessary to accommodate the interconnection requests, the cost of which are typically assigned to the interconnecting generators.

The generator interconnection processes used by grid operators today were designed decades ago for the interconnection of a limited number of large generating plants. They are unable to handle quickly and efficiently the large number of interconnection requests today. As a result, generator interconnection queues have grown to levels that create long delays in realizing the necessary interconnection capacity and the associated development of new generating capacity.

To address the generator-interconnection-related delays, FERC issued Order 2023 in June of 2023. With this order, FERC aims to streamline and speed up generator interconnection processes. If actually implemented by grid operators, some of these reforms have the potential to significantly speed up generator interconnection processes, particularly at existing POIs and new POIs that do not require significant network upgrades—although additional reforms, such as integrating generator interconnection needs into more proactive and holistic transmission planning, will be necessary to achieve more timely and cost-effective outcomes.

FERC has recognized that holistic long-term transmission planning is desirable to avoid the inefficiencies created by the siloed current planning processes. Planning that holistically considers more than one transmission driver simultaneously is referred to as "multi-value" or "multi-driver" planning, enabling a single investment (a multi-driver solution) that can simultaneously and more cost-effectively address multiple needs. Holistic planning is particularly valuable now as the need to refurbish or replace transmission infrastructure originally deployed during the rapid expansion of the U.S. electric grid during the middle of the 20th century logically drives a significant portion of today's high level of local transmission investments. The large number of transmission facilities built in the 1950s, 1960s, and 1970s are now reaching the end of their useful lives and must be refurbished to maintain reliability. Through more holistic and forward-looking analyses, planners could evaluate a wide range of transmission needs, including local or asset replacement needs, and identify projects that can more cost effectively address the various types of transmission needs and better utilize the rights of way of aging existing lines.

The process used to set transmission service rates uses two steps: determining "revenue requirement" and then calculating the "transmission rate." FERC applies traditional cost of service regulation (COSR) or rate of return (ROR) regulation to determine the transmission revenue requirement, which is the annual amount of revenues that must be recovered from transmission customers to recover the full cost of transmission projects, including capital and other development costs, operating and maintenance costs, taxes, and a FERC-allowed return of investment based on estimates of the TOs' cost of capital.

The revenue requirement is then allocated to transmission service customers to design a set of transmission service rates applicable to different types of transmission service. Precisely how the cost of regulated transmission facilities are allocated to utilities and users within a region typically varies by the type, driver, or voltage level of the transmission facility. A utility's own transmission costs and its share of allocated regional transmission costs are ultimately charged to loads in its service area. These transmission costs are then recovered from end-use customers through state-jurisdictional retail rates based on state-commission cost allocation rules.

FERC requires that the costs borne by different groups of ratepayers for each transmission facility are roughly commensurate with the benefits the facility provides to those customers. In light of this standard, FERC and the courts have allowed for significant regional variation in the particular methods of identifying beneficiaries and allocating costs associated with facilities selected in the regional plan for purposes of regional cost allocation (pursuant to Order 1000). The initial step of selecting a cost allocation method is mandated by Order 1000, as facilities cannot be selected in a regional plan without an approved regional cost allocation method for the particular type of transmission facility.

Generally, cost allocation approaches tend to share the costs of regional projects more or less broadly throughout the region, for example based on variations in peak loads. This tendency is enforced by recent court decisions, which have applied the cost causation principle in determining that large, high-voltage network transmission facilities provide regional benefits, limiting cost allocations that are too narrowly applied to only one set of customers.

The process of determining wholesale or interstate transmission rates takes one of two forms: "stated rates" or "formula rates." The transmission-owning utility chooses which type of rate setting process it will use at FERC to determine its revenue requirements and associated transmission rates. FERC has expressed a preference for formula rates, noting that they encourage "certainty of recovery that is conducive to large transmission expansion programs." As a result, most TOs utilize formula rates, particularly in ISO/RTO regions but also in areas outside organized wholesale markets.

Stated rates require that a utility files a "rate case" with FERC under which rates are developed based on the current snapshot (or projected) revenue requirements. Once determined in the rate case, these rates then remain in effect until a new rate case is filed by the TO. Under formula rates, a utility initially submits a spreadsheet template (the "formula"), designed as a framework to annually calculate updated revenue requirements. This template is subject to FERC review and approval when initially filed, similar to a typical change in a utility's Tariff. After this initial approval, the underlying formula remains unchanged (until the utility elects to change it). However, each year, the utility updates the formula rate "inputs," resulting in an annual update of its transmission revenue requirements and associated per-unit transmission rates.

As part of their jurisdiction over distribution utilities, states retain regulatory authority over the retail electric bills sent to end-use customers. While wholesale transmission service is FERC-jurisdiction, ultimately, the revenues and costs associated with transmission service provided and received pursuant to FERC-approved wholesale transmission rates must be recovered in state-jurisdictional retail rates paid by retail customers in various states. Because federal rates preempt state authority, and a state cannot limit recovery of a federally approved rate, transmission charges are explicitly or implicitly included in every end-use customer's state-regulated electricity bill. While state regulators can participate in the transmission planning process and FERC transmission rate cases as stakeholders and retain authority to decide how transmission costs are recovered from different retail rate classes (e.g., commercial, industrial, residential, etc.), state utility commissions ultimately do not have the authority to disallow recovery of transmission costs approved by FERC.

—Summary by Trinity White

Commentary.

Evaluating the Impact of the BIG WIRES Act

By: Audun Botterud,

Christopher R. Knittel, John E. Parsons,

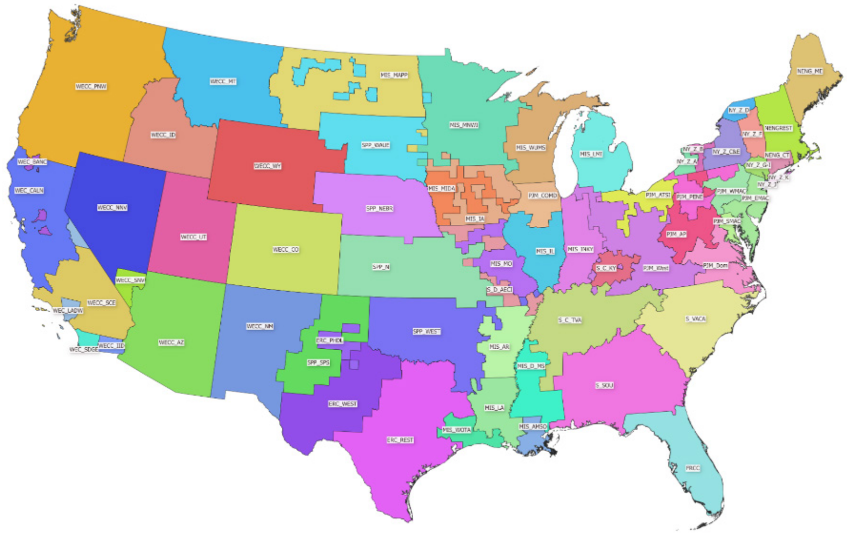
and Juan Ramon L. Senga

Introduction

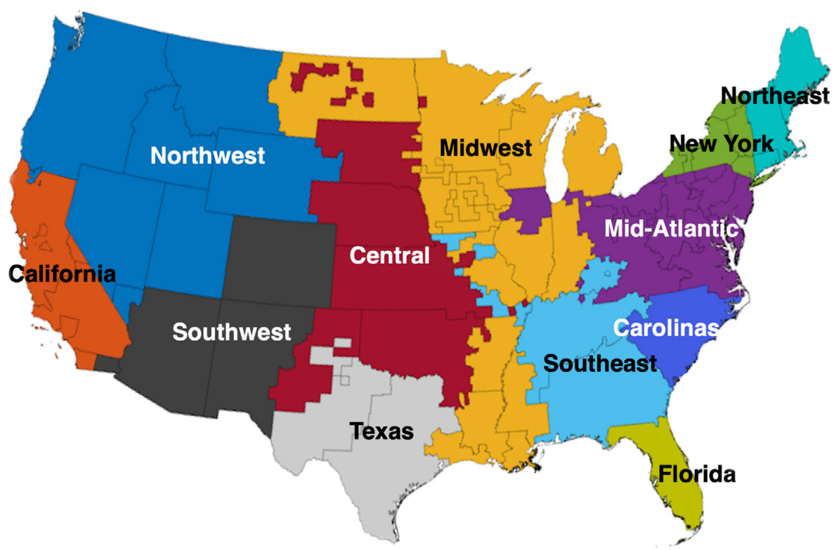
Building interregional transmission is critical to a decarbonized and more resilient U.S. grid. However, according to the most recent DOE Transmission needs study, planned transmission builds up to 2035 are lagging behind the country's anticipated need (DOE, 2023). Several barriers exist to building transmission. These include insufficient coordination between different transmission planning regions brought by the prioritization of local clean energy goals, cost allocation concerns, NIMBYism, and the perception that benefits may not be realized for their own region (Joskow, 2020; Kasina and Hobbs, 2020; Pfeifenberger et al., 2021). To address these challenges, the BIG WIRES Act (S.2827 - 118th Congress) was proposed in the U.S. Congress and would require transmission planning regions to achieve minimum interregional transfer requirements. The bill requires that each FERC Order No. 1000 region should have the capability to transfer at least 30% of its coincident peak load to neighboring regions by 2035 (Hickenlooper and Peters, 2023). The intent is to incentivize coordination among the regions and get part of the benefits of a fully connected grid. In this research commentary, we summarize the key results of a soon-to-be-released working paper that is focused on determining the impact of the BIG WIRES Act. We aim to use insights derived from this work to further the conversation on current and future legislation pushing for minimum interregional transfer requirements.

To undertake the analysis, we use the capacity expansion model, GenX. We evaluated the BIG WIRES Act in four areas: (1) interregional transmission builds, (2) electricity system cost savings, (3) climate benefits, and (4) grid resiliency to extreme weather events.

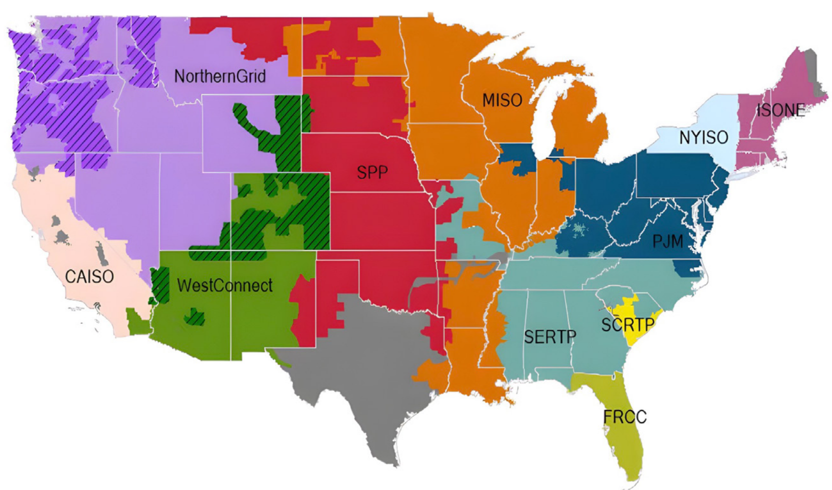
Our evaluation compares two systems: one where we impose a Minimum Interregional Transfer Capacity (MITC) constraint and another where there is no MITC. These two systems represent the cases where the BIG WIRES Act is and is not implemented, respectively. We also examine two future decarbonization scenarios, namely, one



(a) 64 Zone map



(b) 12 Model Region Map created by aggregating the 64 zones



(c) FERC Order No 1000 Transmission Planning Regions

Figure 1: Zonal and Regional Maps

without any CO_2 emissions reduction target and another with a 95% CO_2 emissions reduction target vs 2005 levels. These two scenarios illustrate how the BIG WIRES Act interacts with other policies that may be implemented. The systems are all examined for the year 2035.

The first step to modeling the BIG WIRES Act within GenX is representing the 11 FERC Order No. 1000 transmission planning regions. To do so, we adapt Shi (2023). Shi (2023) creates 64 zones within the continental U.S. within GenX, shown in Figure 1a. We group these zones (Figure 1b) to best mimic the FERC transmission planning regions and Texas (Figure 1c). We define any transmission that is built between zones within the same region as *intraregional* and transmission built between zones from different regions as *interregional*. We assume that not implementing the BIG WIRES Act leads to no new interregional transmission being built. We also assume that only enough interregional transmission to satisfy the MITC requirements will be built if the BIG WIRES Act is implemented. In both cases, zones can build new intraregional transmission. This mimics the inclination of Balancing Authorities (BAs) to build within their own transmission planning region while having barriers to building interregional transmission.

We now proceed with the summary of our evaluation of the BIG WIRES Act, answering the main questions associated with each of the four areas.

1. Where and how much interregional transmission will be built?

Figure 2 shows the existing and additional transmission capacity under the status quo and the BIG WIRES Act, respectively. The decision on where to build transmission starts with a proportional increase in the maximum allowed transfer capacity between zones based on existing transmission infrastructure. The maximum allowed transfer capacity is then increased until the MITC can be met in all regions. Then, GenX determines where to build interregional transmission based on which alternatives lead to the least total system cost while ensuring MITC requirements are satisfied. Table 1 shows the interregional transmission builds and transfer capacities per corridor. We estimate that an additional 13.52 TW-mi of interregional transmission will be built, equivalent to 56.11 GW of additional transfer capacity. Most of the expansion is concentrated in the Eastern Interconnect between the

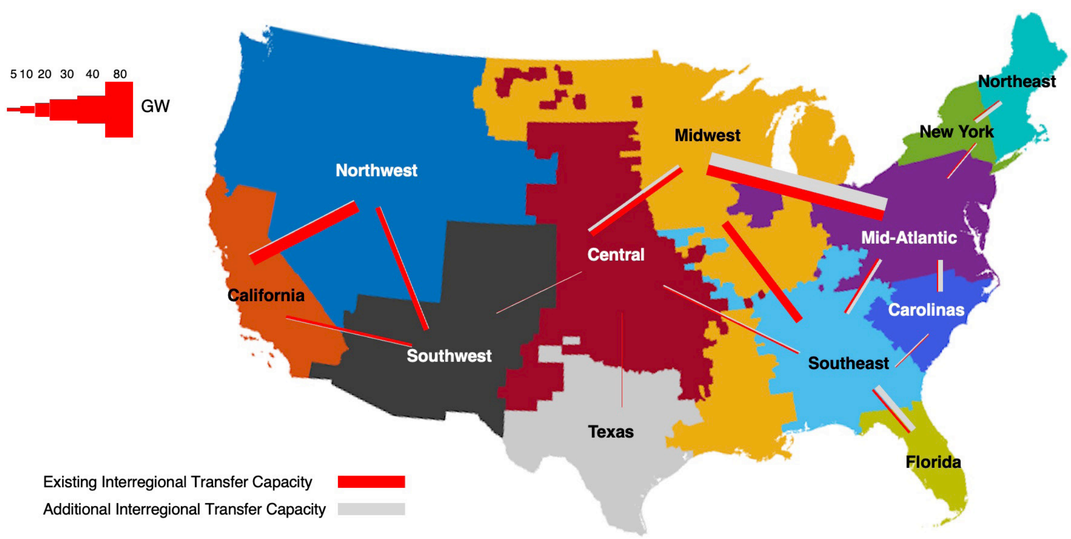


Figure 2: Map of existing and additional interregional transfer capacity between regions

	Transfer Capacity (GW)			Transmission Builds (TW-mi)		
Corridors	Existing	Additional	Total	Existing	Additional	Total
California – Northwest	14.73	1.77	16.50	5.40	0.52	5.92
California – Southwest	4.35	1.17	5.52	1.30	0.35	1.65
Northwest – Southwest	7.44	0.73	8.17	1.97	0.19	2.17
Southwest – Central	0.61	0.48	1.09	0.14	0.11	0.24
Southeast – Central	2.30	1.45	3.75	0.67	0.42	1.10
Florida – Southeast	3.60	8.65	12.25	1.21	2.90	4.10
Carolinas – Southeast	1.62	1.33	2.94	0.55	0.45	0.99
Carolinas – Mid-Atlantic	2.22	7.03	9.25	0.61	1.92	2.53
Mid-Atlantic – Midwest	16.55	18.01	34.56	3.56	3.67	7.23
Mid-Atlantic – New York	1.92	1.62	3.54	0.28	0.21	0.49
Mid-Atlantic – Southeast	3.33	4.30	7.63	0.80	1.04	1.84
Midwest – Central	7.51	4.64	12.15	2.20	1.35	3.55
Midwest – Southeast	11.87	-	11.87	2.63	-	2.63
Northeast – New York	2.16	4.92	7.08	0.17	0.38	0.55
	80.20	56.11	136.31	21.48	13.52	35.00

Table 1: Existing and additional interregional transfer capacity and transmission builds per corridor

Midwest and the Mid-Atlantic (3.67 TW-mi deployment; 18.01 GW additional transfer capacity), Southeast and Florida (2.90 TW-mi; 8.65 GW), Mid-Atlantic and Carolinas (1.92 TW-mi; 7.03 GW), Midwest and Central (1.35 TW-mi; 4.64 GW), and Mid-Atlantic and Southeast (1.04 TW-mi; 4.30 GW). New interregional transmission deployment in these corridors represents 80% of the total additional interregional transmission builds (in TW-mi) and 75% of additional transfer capacity (in GW) under the BIG WIRES Act.

2. How much will the BIG WIRES Act save?

We calculate that the BIG WIRES Act leads to annual system cost savings of \$330 million for the no CO_2 reduction target scenario and \$2.46 billion for the 95% CO_2 reduction target scenario, relative to the status quo. This result shows that the BIG WIRES Act facilitates larger savings in low-carbon systems. We examined this further in Figure 3, illustrating the cost differences between the BIG WIRES Act and the status quo for each cost component. In the no CO_2 target reduction scenario, the savings are driven by lower fuel costs from increased solar and wind generation capacity investments. This re-emphasizes how interregional transmission increases the viability of renewables by giving regions access to more quality wind and solar resources (Brown and Botterud, 2021; Joskow, 2020). In the 95% CO_2 reduction target scenario, there are savings on investments in new generation and storage capacity. The high-decarbonization target means a greater reliance on renewables, leading to a larger solar, wind, and battery storage fleet than when there is no CO_2 target. Having additional interregional transmission facilitates the use of more efficient renewable resources in regions such as the Mid-Atlantic, Central, and Northeast, leading to more generation from renewables even with less capacity investments. Notably, investment in new intraregional transmission also increases in both scenarios because more renewables under the BIG WIRES Act also rely on being able to transfer electricity within each region effectively.

We also evaluated variation in the MITC in the BIG WIRES Act to find the optimal percentage of peak load (i.e., MITC % Peak Load). Figure 4 shows the annual system cost at different MITC % Peak Load for the no CO_2 and 95% CO_2 reduction target scenarios. The dashed horizontal line represents the system cost of the status quo. Based on 5%

Figure 3: System cost difference of the BIG WIRES Act vs Status Quo (Billion \$)

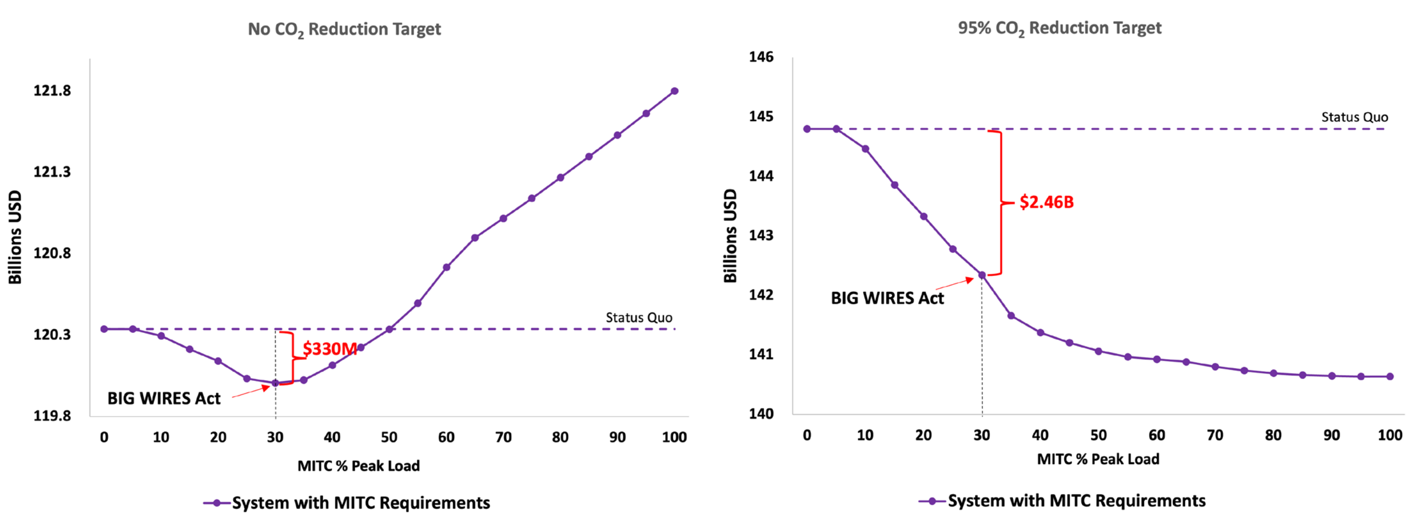


Figure 4: Annual system cost curve per MITC % Peak Load Calculation

increments from 0 to 100% of peak load, an MITC constraint between 5 and 50% of peak load leads to cost savings in the no CO_2 reduction target scenario. Below 5%, regions would already meet the MITC, and beyond 50%, the costs of adding more transmission are higher than the cost savings. Interestingly, the optimal in this scenario is at 30%—exactly what the BIG WIRES Act proposes. In the 95% CO_2 reduction scenario, there is savings beyond 5% of peak load, and the minimum is at 95%.

2.1. Which regions will see savings and cost increases?

We assume that costs associated with a generation facility are assigned to a region where the facility is located. Given this assumption, the results in Table 2 show that the California, Carolinas, Midwest, New York, and Texas regions will all have savings under the BIG WIRES Act in both decarbonization scenarios while the Central, Mid-Atlantic, Northeast, and Southwest regions will have increased costs. The increase in both decarbonization scenarios is primarily due to combinations of increases in wind generation investments, higher fixed operating and maintenance costs, and interregional transmission builds. It is important to note that an increase in costs is not necessarily a negative impact on the region. Table 3 reports the change in exports and imports from and to each region. In those regions, we see an increase in costs, and we also see an increase in electricity exports to other regions, thereby increasing regional revenues.

3. What are the climate benefits of the BIG WIRES Act?

The BIG WIRES Act leads to a 73 million metric tons (Mmt) (5.5%) reduction of CO_2 emissions relative to the status quo. This is equivalent to a \$14 billion reduction in climate damages based on the new proposed EPA social cost of carbon of \$190 per mt (EPA, 2023). The emissions reduction is again because of the increased penetration of renewables and the consequent reduction of coal. In the 95% CO_2 reduction setting, the climate benefit is the \$2.46 billion less spending to achieve the CO_2 target.

	No CO_2 Reduction Target			95% CO_2 Reduction Target		
	No BIG WIRES	With BIG WIRES	Difference	No BIG WIRES	With BIG WIRES	Difference
California	4.81	4.73	(0.08)	5.33	5.28	(0.05)
Carolinas	8.46	7.69	(0.77)	10.79	9.54	(1.25)
Central	5.44	5.64	0.19	6.11	6.56	0.45
Florida	9.11	9.51	0.41	11.54	10.08	(1.46)
Mid-Atlantic	27.64	28.91	1.27	31.05	31.52	0.48
Midwest	20.59	20.13	(0.46)	26.04	24.78	(1.26)
New York	4.04	3.86	(0.18)	4.82	4.65	(0.17)
Northeast	3.67	3.79	0.12	4.32	4.67	0.35
Northwest	5.42	5.44	0.03	6.78	6.66	(0.12)
Southeast	15.68	14.84	(0.84)	19.68	20.21	0.53
Southwest	5.24	5.29	0.05	6.76	6.87	0.11
Texas	10.24	10.17	(0.07)	11.56	11.49	(0.07)
Total	120.33	120.00	(0.33)	144.76	142.31	(2.45)

Table 2: Cost per region under each scenario in billion \$.
(Note: Costs are assigned based on where generation facilities are located. The cost of transmission investment between two regions is allocated proportionally to load)

	No CO_2 Reduction Target			95% CO_2 Reduction Target		
	No BIG WIRES	With BIG WIRES	Difference	No BIG WIRES	With BIG WIRES	Difference
California	(38.3)	(40.2)	(2.0)	(47.4)	(49.4)	(2.0)
Carolinas	(10.3)	(22.1)	(11.8)	0.4	(11.7)	(12.2)
Central	28.9	44.7	15.7	14.3	36.2	21.8
Florida	2.8	7.9	5.0	(0.3)	(24.6)	(24.3)
Mid-Atlantic	(8.4)	25.6	34.0	(35.0)	(23.0)	12.0
Midwest	28.9	19.2	(9.7)	50.0	47.2	(2.7)
New York	(4.7)	(11.0)	(6.3)	(1.0)	(7.8)	(6.8)
Northeast	(3.1)	(0.1)	3.0	1.1	10.7	9.6
Northwest	19.1	19.3	0.2	21.8	19.9	(1.9)
Southeast	(32.3)	(60.5)	(28.2)	(28.3)	(24.2)	4.1
Southwest	17.6	18.4	0.8	23.8	26.3	2.5
Texas	(0.4)	(1.1)	(0.6)	0.6	0.5	(0.1)

Table 3: Net regional electricity exports (imports) in TWh.

4. Does the BIG WIRES Act reduce the impact of extreme weather events?

To answer this question, we simulated 1000 random outages at the same scale as Winter Storm Elliot which led to 80.5 GW of generation capacity going offline in the Mid-Atlantic, Southeast, and Carolinas in December 2022 (Howland, 2023). We found that the average number of homes affected in these regions is reduced from 4.7 million in the status quo to 2.1 million under the BIG WIRES Act. This represents a 58% reduction in power outages and is mostly due to increased transfers from New York and the Midwest into the Mid-Atlantic. Figure 5 shows the distribution of outages from the simulation of the status quo and the BIG WIRES Act across the 1000 simulated storms.

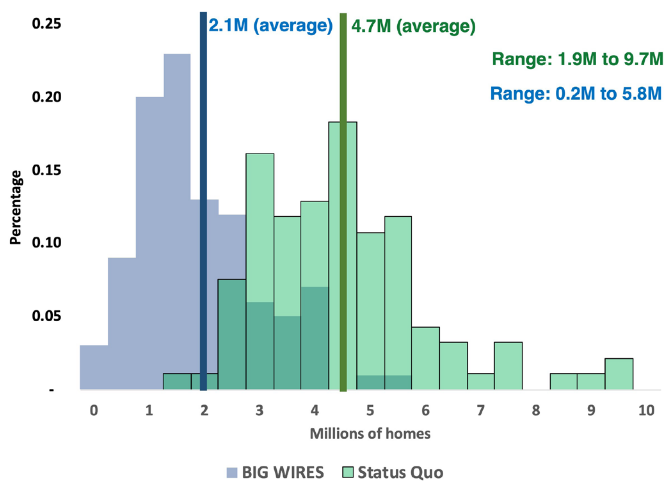


Figure 5: Distribution of number of homes experiencing an outage

Conclusion

In this research commentary, we present the results of an evaluation of the BIG WIRES Act, a proposed legislation that would mandate minimum interregional transfer capacity among the FERC Order No. 1000 transmission planning regions. Using the capacity expansion model GenX, we compared two systems: one with and one without the MITC constraint, under two decarbonization scenarios: one with no CO_2 reduction target and one with a 95% CO_2 reduction target vs 2005 levels. Our main findings are:

- The BIG WIRES Act would significantly increase the interregional transmission capacity across the U.S., especially between the regions with high renewable potential and high demand.
- The BIG WIRES Act would reduce the electricity system cost by \$330 million annually in the no CO_2 reduction scenario and by \$2.46 billion annually in the 95% CO_2 reduction scenario, compared to the status quo.
- The BIG WIRES Act would enable higher penetration of renewable energy sources, resulting in lower CO_2 emissions. The CO_2 emissions would decrease by 73 Mmt annually in the no CO_2 reduction scenario and reduce the costs of meeting a 95% reduction in CO_2 by \$2.46 billion annually, relative to the status quo.
- The BIG WIRES Act would enhance the grid resiliency to extreme weather events, such as heat waves, cold snaps, and hurricanes, by providing more flexibility and diversity in the generation mix and reducing the reliance on natural gas. For the case of a storm of similar magnitude to the Winter Storm Elliot of 2022, the BIG WIRES Act leads to a 58% reduction in power outages, on average.

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Authors' note: *The results presented here are preliminary and updated findings and analysis on the BIG WIRES Act will be released in the CEEPR Working Paper version of this commentary, which will be published in the near future.*




Audun Botterud, Christopher R. Knittel, John E. Parsons, and Juan Ramon L. Senga (2024), "Research Commentary: Evaluating the Impact of the BIG WIRES Act", CEEPR RC-2024-01, MIT, January 2024. For references cited in this story, full bibliographical information can be found in the Working Paper.

Research.

A Supply Curve for Forest-Based CO_2 Removal

By: Sergio L. Franklin Jr.
and Robert S. Pindyck

Global CO_2 emissions are continuing to rise. That may eventually change, but even with a substantial decline in emissions, the atmospheric CO_2 concentration will keep growing and remain high for many years. That is why policy objectives have focused on net emissions, and the need to remove CO_2 from the atmosphere. But how? Planting trees (afforestation; the practice of establishing forests on land that were not previously forested and reforestation; the practice of reestablishing forest that have been cut down or lost to natural causes) might be seen as an obvious solution, but where and at what cost? Here we focus on forested and forestable land in South America, and use spatially disaggregated data to estimate a supply curve for forest-based atmospheric CO_2 removal. The supply curve traces out the marginal cost of removing a metric ton of CO_2 as a function of total annual CO_2 removal. Each point on the curve corresponds to a specific location, so our analysis tells us where and how many trees can be planted, and at what cost.

So why don't we start planting large numbers of trees? Yes, it would take time, but after 10 years or so, net emissions could be substantially reduced. We are indeed planting some trees, but cutting down many more (see Figure 1). From 2015 to 2020, there were about 10 million hectares per year of deforestation, which was partly offset by about 4 million hectares per year of forest gain, for an annual net forest loss of about 6 million hectares. Deforestation occurs because land is valuable, and can be used for agriculture, cattle grazing, mining, and other economic activities. And that is one of the main reasons why we are not planting trees in sufficient numbers to have a significant impact on net CO_2 emissions. Planting and maintaining trees requires valuable land, which can make it costly.

Suppose deforestation at recent rates continues. What impact would an ongoing loss of, say, 6 million hectares per year have for CO_2 emissions? Each year CO_2 absorption is reduced (i.e., net emissions are increased) by .06 Gt per year, or about 1 Gt after 17 years. But net

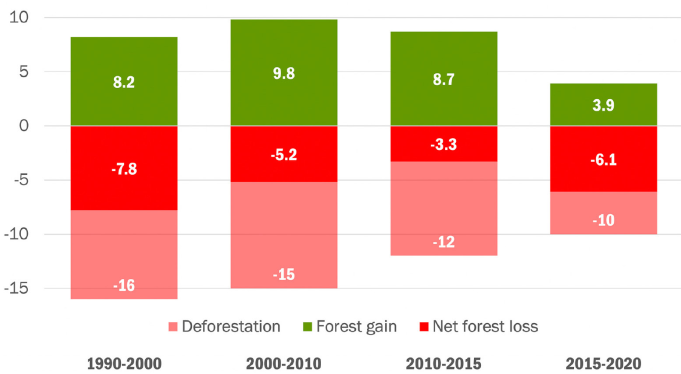


Figure 1. Net Annual Forest Loss.
Source: United Nations' Food and Agriculture Organization (2020 b) and https://rainforests.mongabay.com/deforestation/

emissions actually increase by much more, because a tree contains about 200 kg of carbon, which releases around 700 kg of CO_2 when the fallen tree decays or (more often) is burned. This in turn implies that an ongoing loss of 6 million hectares per year would increase net CO_2 emissions by 0.27 Gt per year, or about 1 Gt after four years. Deforestation is a serious problem, but our focus is on forestation. How many hectares can potentially be forested, and at what cost? Macro-level estimates attempt to account for the land that is potentially forestable, but tell us very little about forestation costs, which vary considerably across regions. The variation is due to sharp regional differences in the current use of the land, and in rainfall and other climatic factors that affect forest growth.

We address this problem at the micro level and develop a supply curve for forest-based CO_2 removal. The supply curve traces out the marginal cost of removing 1 ton of CO_2 from the atmosphere as a function of total annual CO_2 removal, all by planting trees. Given data limitations, we focus on forested and forestable areas in South America, which include the Amazon rainforest (accounting for 13 percent of the world's total forest area), the Atlantic forest, the Gran Chaco region, and areas of savanna and grassland.

We consider planting trees in areas that during the past 50 years were once densely forested but have experienced forest loss, as well as areas that were never forested and may instead have existed as savanna or grassland. Our analysis accounts for the three most important types of cost involved in forestation:

1. Opportunity cost of land. This varies greatly across locations, and is often the largest cost component for forestation. Deforestation occurs because land has economic value, and foresting a hectare of land means it cannot be used for other purposes.

2. Planting and maintenance costs. Planting a tree involves more than sticking an acorn in the ground. It begins with planting and growing seedlings, and then replanting those seedlings with fertilizer, water, and insect repellent. Later, the trees must be protected from insects and pruned as they mature, and sometimes must be replanted. Mature trees have ongoing maintenance costs, which includes continual addition of fertilizer and insect repellent, and depending on the area, water.

3. Forest conservation costs. Later, mature trees must be protected from illegal logging, which is a serious problem in much of the world. Monitoring and law enforcement efforts must be put in place in order to ensure forest conservation.

Based on these costs, we determine where and how many trees can feasibly be planted. We mentioned that water is a critical input; indeed forestation in areas with limited rainfall is usually prohibitively expensive, and most areas deemed suitable for forestation have considerable rainfall. In developing a supply curve for South America, we consider areas where precipitation patterns can potentially support forest growth. The objective is to determine where precipitation patterns make it economical to plant trees and the number of trees that should be planted.

Land opportunity and tree planting costs also vary considerably across regions, as precipitation does. Thus much can be gained by a more micro level approach to the use of forestation for CO_2 removal. To show why, Figure 2 below presents one of our main results - a supply curve for forest-based atmospheric CO_2 removal in South America. The curve shows the marginal cost of removing (via forestation) one ton of CO_2 as a function of total forest-based annual CO_2 removal.

Point A on the curve shows the lowest cost ($23 per ton) at which CO_2 can be removed from the atmosphere by planting and maintaining trees in South America. This is the lowest-cost location in part because of plentiful rainfall, but also because of relatively low tree planting and land opportunity costs.4 Point B is also in the Amazon forest of Brazil, state of Para. As at Point A, here rainfall is plentiful, but tree planting costs are higher, so the cost of removing CO_2 is $30 per ton. Point C is in the Amazon forest of Brazil, state of Mato Grosso. Land opportunity costs are higher so the cost of removing CO_2 is $40 per ton. Finally, Point D, at the top of the curve, is in the Brazilian Cerrado. This area is largely savanna, with lower forestation potential and higher land opportunity costs, so the cost of removing CO_2 is about $90 per ton. Figure 2 shows that regional variations in the marginal cost of forestation are large.

We know a single tree can absorb 10 to 40 kg of CO_2 per year, depending on climate and the age and type of tree, so to estimate the average CO_2 absorption rate for a land grid element, we must account for the variety of trees it contains. We find the total carbon stock accumulation (above and below ground) is 3.0 tons of carbon per hectare per year, or $3.0 \times 3.67 = 11$ tons of CO_2. Given an average tree density of 600 trees per hectare, we estimate the average CO_2 absorption rate to be $11{,}000/600 = 18.333$ kg CO_2 per tree per year. These estimates apply to trees in tropical moist forests; we use them here because our forestation target zone consists of areas in South America where precipitation patterns are similar to those in tropical forests.

Finally, the cost of planting and maintaining trees is also dependent on

Sergio L. Franklin Jr. and Robert S. Pindyck (2024), "A Supply Curve for Forest-Based CO_2 Removal", CEEPR WP-2024-04, MIT, March 2024.

the choice of forest recovery technique. Different forest recovery techniques imply different activities and inputs, and thus different costs. "Facilitating natural regeneration" is most economical for land grids with high tree cover (55-65%), "enhancing tree density and enrichening" is frequently used for land grids with medium tree cover (30-55%), typically on the margins of remnant forest areas and in large clearings, and "total planting" is usually most appropriate for land grids with low tree cover (5-30%). Economies of scale make it uneconomical to plant small numbers of trees, so we only consider areas where the forestation potential is at least 10%.

Looking back at Figure 2, each point on the curve shows the cost per ton of CO_2 removed for a land grid element in the forestation target zone as a function of total annual CO_2 removal. The figure shows that a carbon price at or below \$20/tCO_2 will have no impact on forest-based CO_2 sequestration, a carbon price of \$45/tCO_2 can induce the sequestration of 1.5 Gt of CO_2 per year, and a carbon price of \$90/tCO_2 can induce the sequestration of 2.5 Gt of CO_2 per year. Reductions in agricultural land need not imply higher food prices. Different Brazilian regions and South American countries have different agricultural products, so reductions in agricultural areas can be compensated for by the adoption of best production practices.

Our supply curve applies to only South America, but with sufficient data could be extended to the entire world. If the rest of the world looks like South America (in terms of its potential for forestation), and our supply curve were scaled up accordingly, a considerable amount of CO_2 could in principle be removed from the atmosphere via forestation. But doing so would be costly. For example, reducing net CO_2 emissions by 25% via forestation would cost something around \$1 trillion annually, which is about 1 percent of world GDP.

One could take issue with several aspects of our analysis. First, we have effectively assumed that trees last forever, which is clearly not the case. When trees die, the carbon they have sequestered will be released back into the atmosphere as CO_2. Thus, it might seem that planting trees cannot sequester CO_2 over the long run because those trees will eventually die. But the key is "eventually." Trees can live for a few hundred years, so trees planted now will sequester CO_2 for many years before those trees will have to be replanted. (Recall that our supply curve is based on a 50-year time horizon.) We have ignored potential demand shifts and innovations in agriculture and in forestry that might occur over the next 50 years. We have also ignored other benefits that forestation can provide, such as water recycling, erosion control, and short-term climate regulation. These benefits have external economic value, and from a public policy perspective should affect the supply curve by reducing the "full" marginal cost of CO_2 removal. Lastly, we have not addressed the cost of maintaining existing forest areas, so as to reduce CO_2 emissions from deforestation. Because data limitations have limited our analysis to South America, this paper might be viewed as a "proof of concept".

—Summary by Trinity White

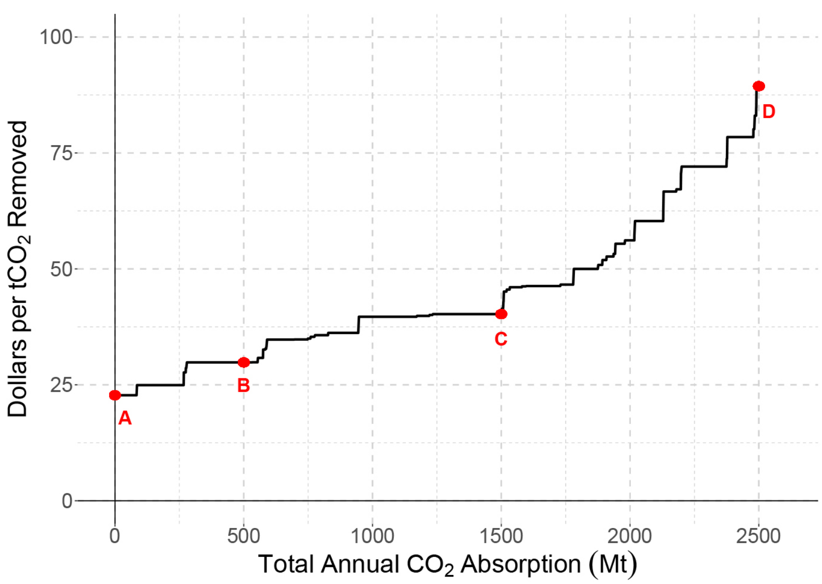


Figure 2. Supply curve for forest-based atmospheric CO_2 removal in South America.
The curve shows the marginal cost (in 2020 US dollars) of removing one ton of CO_2 per year as a function of total forest-based CO_2 removal. Each point on the curve corresponds to a land grid element.

Chi Kong Chyong, Eduardo Italiani, and Nikolaos Kazantzis (2023), "Implications of the Inflation Reduction Act on Deployment of Low-Carbon Ammonia Technologies", CEEPR WP-2023-21, MIT, November 2023.

Research.

Implications of the Inflation Reduction Act on Deployment of Low-Carbon Ammonia Technologies

By: Chi Kong Chyong, Eduardo Italiani, and Nikolaos Kazantzis

Ammonia is a pivotal energy vector in the ongoing global energy transition, serving as a versatile feedstock and a prospective low-carbon fuel for diverse applications, including electricity, maritime transport, reliable storage and transport medium for low-carbon hydrogen (IEA, 2021; IRENA, 2022). Further, ammonia benefits from an established global market and relatively mature infrastructure. Yet, ammonia accounts for 3% of global CO_2 emissions, with a carbon intensity that outpaces even steel and cement (IEA, 2021; Smith et al., 2020). The prevailing ammonia production (AP) pathway, reliant on steam methane reforming (SMR) and the Haber-Bosch (HB) process, is predominantly fossil-fuel-based (natural gas and coal) (Salmon et al., 2021). However, its decarbonization remains a formidable challenge, necessitating technological and policy interventions to mitigate its environmental impact.

The Inflation Reduction Act (IRA) offers subsidies to scale up low-carbon energy technologies in the United States. This paper evaluates the economic impacts of the IRA on low-carbon ammonia production (LCAP) technologies, focusing on technology, policy, and market uncertainties. We use a stochastic Discounted Cash Flow (DCF) model to assess the IRA's financial provisions for LCAP: conventional SMR, SMR with Carbon Capture System (CCS), indirect biomass gasification coupled with SMR (BH2S), and Alkaline Electrolysis (AEC).

Our modeling results highlight that the successful deployment of LCAP under the IRA depends on the lifecycle carbon intensity (CI) of not just feedstock (natural gas and biomass) but also, crucially, electricity (Figure 1). The IRA framework does not reward (enough) LCAP technologies connected to the US power grid (Scenario A)—although expected to decarbonize significantly under the IRA, the grid is still carbon-intensive to the extent that the subsidies are not matched with the marginal cost of reducing carbon emissions through LCAP, making the incumbent technology—SMR—always economically a better

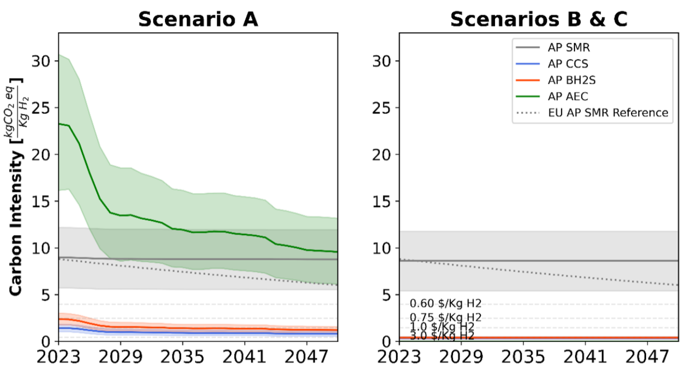


Figure 1. Carbon intensity of AP technologies: grid versus hybrid wind farm

Notes: The numbers shown represent 45V credit bands; the EU AP SMR reference CI is computed based on a set of assumptions (See SI §C); The CI is composed of four components—stack emissions, natural gas upstream, biomass upstream, and electricity. The former three components are time-constant and probabilistic. The latter is time-varying and probabilistic. The uncertainty bands show the minimum and maximum range of carbon intensities. EU AP SMR is assumed deterministic.

choice for investors (Figure 2). This conclusion holds under two time periods analyzed—2026 and 2033—to account for technology improvements and cost reductions. It holds across thousands of Monte Carlo simulations covering critical variables that determine the economics of these technologies.

Then, the critical question the research answers is under what conditions the IRA will likely stimulate the deployment of LCAP. We find that only when LCAP's electricity consumption is carbon-free will we likely witness their economics outperform the SMR's. We distinguish between a vertically integrated business model where an AP investor would build and own an off-grid hybrid wind farm (Scenario B) and a case when the investor signs a long-term power purchase agreement (PPA) with the hybrid wind farm (Scenario C).

Our results show that only under the PPA do the economics of CCS and BH2S outperform SMR in almost all the simulations and years considered. Albeit consuming electricity with zero carbon emissions, the subsidies are insufficient to justify the upfront capital expenditure (capex) for AP investors to build and own the off-grid hybrid wind farm because the near-term cash flow highly influences the Net Present Value (NPV). The build-and-own business model is incredibly unattractive for AEC because of the higher electricity requirement, hence capex, than the other two pathways—CCS and BH2S.

AEC economics heavily depends not just on subsidies but crucially on wind and electrolysis cost reductions. In the near term (2026), AEC will be unlikely to deliver higher NPV (than SMR) in all configurations considered. Only, in 2033, AEC, with IRA subsidies and under the PPA arrangement, offers a 50% higher return (median NPV) than SMR. Most of AEC's economic improvements between 2026-33 are in cost reduction and wind resource improvements. However, CCS and BH2S pathways offer higher NPV (relative to SMR) than the AEC pathway in the near (2026) and medium term (2033). CCS and BH2S offer 60-90% higher economic returns than SMR, outpacing the AEC pathway not just in 2033 but in the near term.

The improvement in AEC's economics due to technology improvements and cost reductions depends on investor participation in early deployment to drive these costs down. If the policy concerns early AEC deployment to drive costs down, IRA subsidies may need to be increased to account for these dynamics (i.e., the $3/kgH$_2$ tranche increased to $4.8/kg). While public attention was focused on the trade-off between the stringency of carbon accounting of the AEC pathway and its early deployment, irrespective of these cost reductions, AEC still underperforms relative to CCS and BH2S in the IRA policy timeline. Thus, technology neutrality in designing policy support for low-carbon technologies is essential. At the same time, the focus should be on stimulating innovation in low-carbon hydrogen technologies and, crucially, their supply chains and market organizations, such as the 24/7 clean PPA market.

The IRA provides unprecedented support for AEC, but the technology underperforms from private and public perspectives: its NPV is lower than those of CCS and BH2S, while its carbon abatement cost (CAC), in most cases, exceeds the social cost of carbon and that of CCS and BH2S. Although marginally exceeding the recent EU carbon prices, IRA subsidy programs are cost-effective in terms of value for public money in supporting hydrogen-based climate mitigation technologies.

It is essential to consider nuances of the US tax credit markets because tax credits under the IRA will not translate into subsidies on a parity level. Thus, the levelized cost approach should explicitly consider these transaction costs. Ignoring the complexity of the tax credit market and its interactions with the PPA markets will result in an underestimation of LCAP levelized cost, especially those with significant barriers to deployment and demonstrate their efficiency at scale (Abolhosseini & Heshmati, 2014; Barradale, 2010; Kahn, 1996). Risky and unproven (at scale) technologies (AEC has the highest risk profile) will involve higher capital costs and verification, compliance, and monitoring costs, potentially significantly increasing transaction costs beyond what this study assumes. Technologies with high-risk profiles will be costlier for the government to support, implying that the government may consider underwriting risks to lower capital costs for investors and, hence, lower support costs per unit of H_2 (e.g., by 12-17% for AEC if its WACC is reduced from 9% to 2%).

In the foreseeable future, there is little chance of putting a price on carbon emissions in the US. Instead, the IRA framework offers unprecedented financial incentives to stimulate private capital into low-carbon energy technologies. On the contrary, the EU's flagship carbon pricing is regarded as the first-best economic policy to tackle carbon emissions (Bennear & Stavins, 2007; Klenert et al., 2018; Nordhaus, 1992). Perhaps not by design, the interactions between the CBAM and IRA will likely mean stronger incentives to decarbonize US AP than standalone IRA. The relatively small carbon taxing and the opportunity to trade CBAM certificates could substantially increase the relative economics of US-based LCAP: grid connection (Scenario A) is now a cost-effective option for at least CCS and BH2S. Under CBAM and

IRA, the CAC to decarbonize US AP via CCS and BH2S could be much lower, falling in the recent range of EU carbon prices. This finding reconfirms the potential effectiveness of multiple policy instruments in a "second-best" world (Bennear & Stavins, 2007; Lehmann, 2012; Sorrell, 2003) to reduce the US AP carbon emissions.

There is considerable debate about consequential emissions from renewable electricity and hydrogen production matching rules. Starting from the monthly matching rule will not unduly penalize AEC's economics while ensuring lower consequential emissions than the yearly rule. While the hourly matching rule ensures limited consequential emissions from the AEC, its unfavorable economics will unlikely stimulate private investment. Hourly-matched AEC pathway seems unlikely a worthwhile avenue to pursue from the public policy perspective because its support cost outweighs the carbon savings benefits (in most cases, AEC's CAC is substantially higher than the social cost of carbon).

AP is expected to almost triple (688 Mt/year) by 2050, with 83% from renewable ammonia (IRENA, 2022). If renewable ammonia is part of this vision, then advancements in the flexibility of the HB process are a crucial avenue for research and development. Some research has highlighted the challenges of flexible HB. The literature reports HB may handle wide ranges of output (5-80% of capacity) and ramping rates (20% capacity/hour) based on feasibility studies and industry opinion (Armijo & Philibert, 2020; Lazouski et al., 2022; Verleysen et al., 2023). However, the demonstration of flexible HB on a small scale only starts, while the additional costs of flexible HB loops on a commercial scale are unclear. Given the current industry state versus the optimistic techno-economic literature, it may be a reality that flexible HB may exist commercially in the next ten years but beyond the IRA timeline. Nevertheless, the incentives for making flexible HB are clear under an electric grid with increasingly fluctuating renewables: our results highlight that the economic benefit of flexible HB could be substantial: \$3.4-7.4 bn or \$96-207/tNH_3.

Thus, to decarbonize AP in the US cost-efficiently, there are key areas for policymakers and the academic community to focus on in the next decade: (i) adapting HB to variable bioenergy quality and process efficiency while ensuring feedstock's sustainability and availability (ii) ensuring safe transport and permanent storage of CO_2 while de-risking CCS value chain, (iii) supporting research and development to drive down cost and efficiency improvements of flexible HB, renewable energy, and electrical and hydrogen-based storage, (iv) policy support framework should ensure technology neutrality and competition while recognizing the nature of "dynamic" technology cost reduction (Gillingham & Stock, 2018) and interactions between policy instruments and between technologies.

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

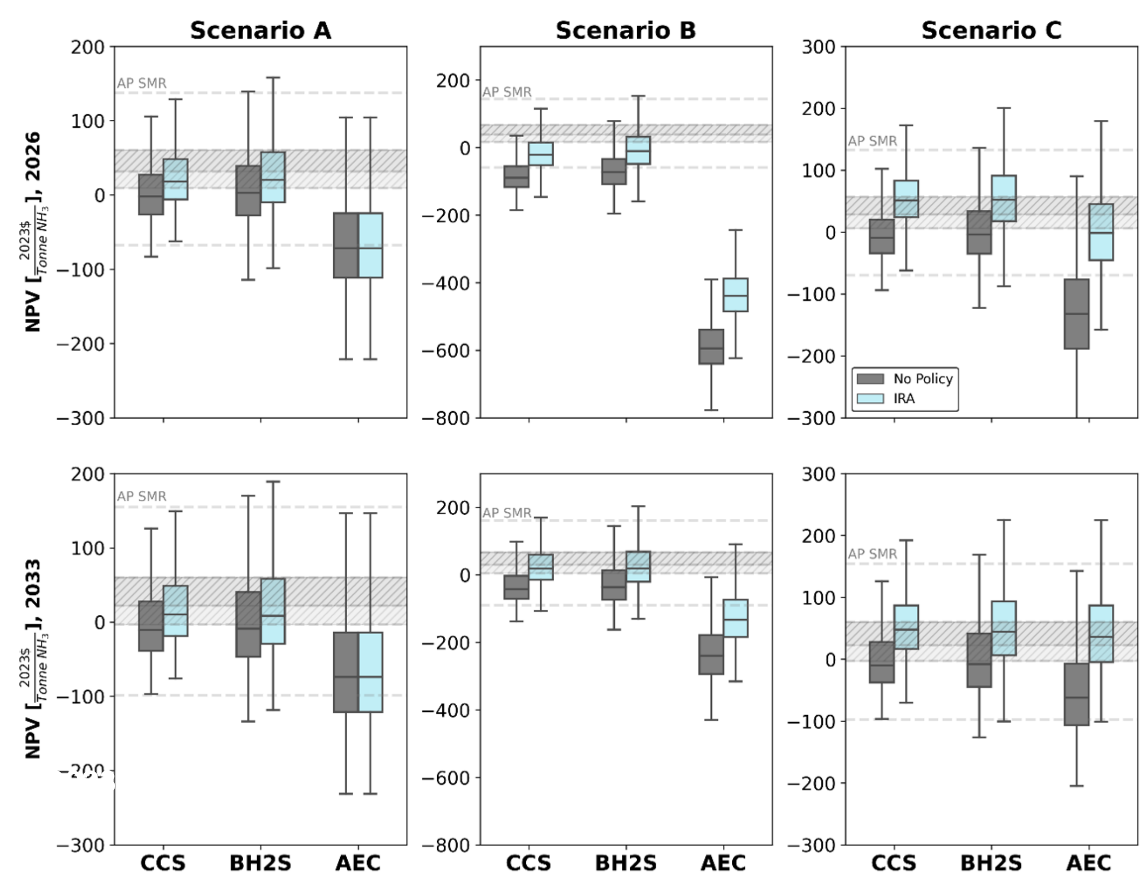


Figure 2. NPV of low-carbon AP technologies

Notes: The NPVs are benchmarked against a control scenario with no policy and AP SMR. Scenarios B and C assume monthly matching between hybrid wind farm output and hydrogen production for AP.

Commentary.

Strategic Sector Investments are Poised to Benefit Distressed US Counties

By: Joseph Parilla, Glencora Haskins, Lily Bermel, Lisa Hansmann, Mark Muro, Ryan Cummings, and Brian Deese

Spurred in part by three significant pieces of federal legislation, since 2021, the United States has experienced an investment surge in "strategic sectors," defined as clean energy, semiconductors and electronics, biomanufacturing, and other advanced industries. So far, economically distressed counties are receiving a disproportionate share of that investment surge relative to their current share of the economy. With comparatively low prime-age employment rates and median household incomes, these counties account for about 8% of national GDP but have received 16% of announced strategic sector investments since 2021. Strategic sector investments are much more likely than private investment overall to target economically distressed counties, relative to recent years and the 2010-2020 recovery period—suggesting a significant departure from geographic patterns of prior investment. Distressed counties that have received a strategic sector investment currently have relatively high shares of employment in advanced industries—suggesting that such foundations continue to matter to private investors. Smaller regions (defined as "micropolitan areas") account for about 25% of the nation's employment-distressed population, but have secured 50% of all strategic sector investments going to distressed counties since 2021. Acknowledging this early progress, the path from private investment into broadly shared and inclusive economic opportunity is not automatic or guaranteed—it requires intentional strategies to connect local workers and businesses to these new investments.

Recent federal legislation—namely, the Infrastructure Investment and Jobs Act, CHIPS and Science Act, and Inflation Reduction Act—was enacted to incentivize investments in several sectors deemed important for America's future economic growth and national security. Coinciding with the passage of this legislation, the United States is experiencing a

$525 billion private investment surge in "strategic sectors," which we define as clean energy, semiconductors and electronics, biomanufacturing, and other advanced industries.

One notable aspect of the many programs these laws fund is their inclusion of special incentives targeted to local economies that can benefit most from new industries, jobs, and economic opportunity. However, there has not yet been a full analysis of the geographic distribution of private sector investment to understand the extent to which distressed communities are benefiting from this place-based industrial strategy.

To fill this gap, this report compares the flow of strategic sector investments in distressed counties to their share of national economic activity, population, and overall private investment levels. We find that economically distressed counties are receiving a disproportionate share of private sector investment in these strategic sectors relative to their economic output and population. We also find that strategic sector investment patterns are distinctive: When compared to private investment writ large, these investments are more likely to go to distressed communities. This pattern of strategic sector investment marks a notable departure from economic growth and private investment trends in the 2010-2020 period.

Finally, we analyze commonalities across distressed communities receiving strategic sector investment, with the aim of informing how policymakers and practitioners can improve economic development outcomes in the implementation of these policies.

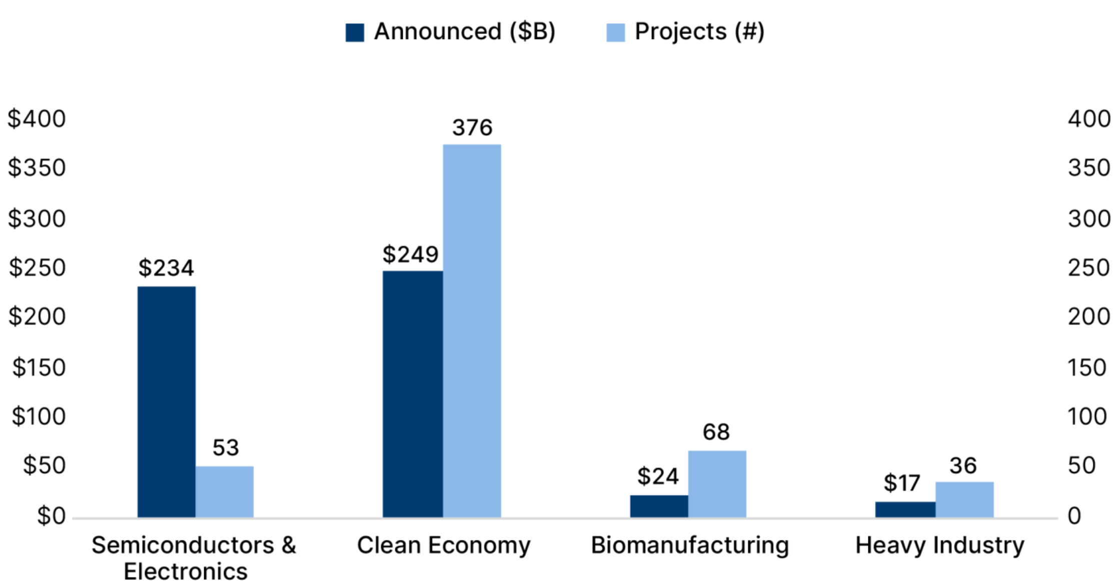
Employment-distressed counties have secured a disproportionate share of strategic sector investments

The United States is experiencing a surge in private investment in "strategic sectors," which we define as clean technology, semiconductors and electronics, biomanufacturing, and other advanced industries. Since 2021, private investors have announced $525 billion in strategic sector investments, as tracked by two sources: 1) the MIT-Rhodium Group's Clean Investment Monitor for clean technology investment; and 2) the White House's Investing in America inventory for microelectronics and advanced manufacturing investments. For more on our data sources and methods, see the appendix, available online at ceepr.link/4aUKe1G.

How and where these capital investments land in local communities will largely determine whether strategic sectors can deliver economic benefits to a broad swath of the country. And indeed, many of the public incentives and investments within the three pieces of industrial strategy legislation seek to push private investment into local areas that are economically distressed. For example, Inflation Reduction Act (IRA) tax credits include bonuses of at least 10% when the investment is located in a low-income or energy community. The IRA Environmental and Climate Justice Block Grants program's $3 billion in funding is only available for grant recipients who are or partner with a community-based organization. And the Department of Energy's new Energy Infrastructure Reinvestment Financing program particularly benefits energy communities with loan guarantees to projects that repurpose or replace energy infrastructure that has ceased operations, as well as projects that reduce the greenhouse gas emissions of energy infrastructure in operation.

The private sector has announced over $525 billion in strategic sector investments since 2021

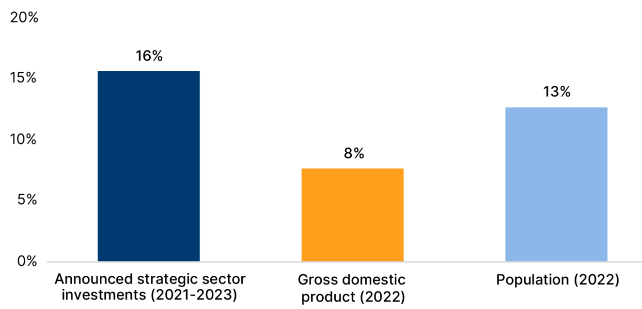
Announced investments in strategic sectors, 2021-2023



Source: Brookings Metro and MIT CEEPR analysis of Clean Investment Monitor and White House Investing in America database data.

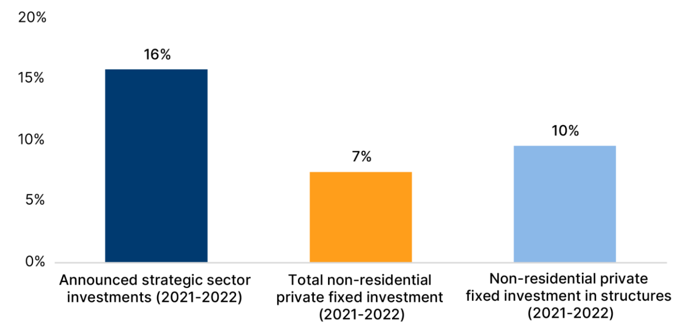
Strategic sector investments have been announced in employment-distressed counties at a significantly higher level than their typical economic output and population share

Strategic sector investments versus economic output and population in employment-distressed counties (share of nation), 2021-2023



Strategic sector investments are flowing into employment-distressed counties at a significantly higher level than other traditional fixed investment

Strategic sector investments versus non-residential private fixed investment in employment-distressed counties (share of nation), 2021-2022



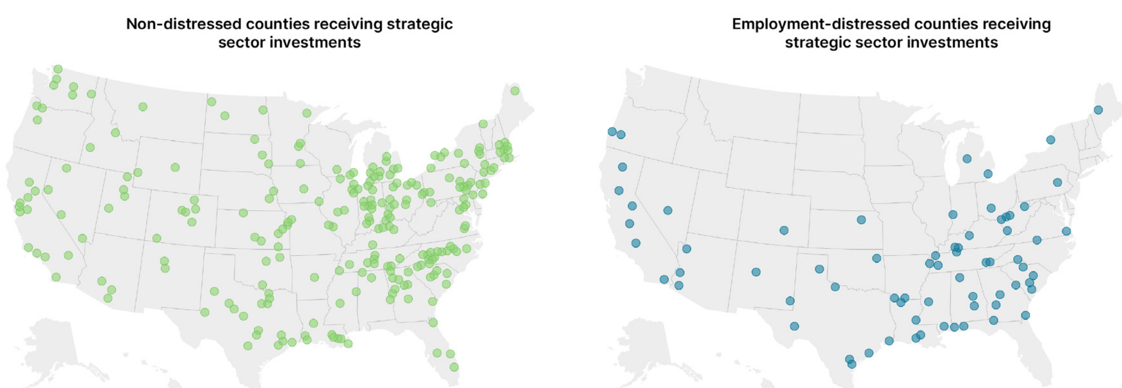
There are several ways to define economic distress. Following the definition used by the Economic Development Administration for its Recompete Pilot Program, we classify counties as "distressed" if they have a prime-age employment gap above 5% and a median household income below $75,000.

As of 2022, the nation's 1,071 employment-distressed counties represented 8% of national GDP and 13% of the U.S. population. Since 2021, these counties received nearly $82 billion (or 16%) of announced strategic sector investments—double that of their GDP share and 1.2 times their population share.

These announced strategic sector investments have flowed to 70 employment-distressed counties in 27 states and across over 100 projects. As Map 1 shows, the employment-distressed counties receiving strategic sector investments are disproportionately concentrated in southern states, though they extend to the West, Northeast, and Midwest as well. The projects include AES and Air Products' plans to invest over $4 billion in Wilbarger County, Texas to build a new mega-scale green hydrogen plant anticipated to create 115 permanent jobs and more than 1,300 construction jobs. Similarly, Chester County, S.C. is the chosen location for Albemarle's $1.3 billion investment to build a "mega-flex" lithium processing facility, which is expected to create at least 300 new jobs.

Comparing strategic sector investments with overall investment patterns suggests this distribution is distinct from private investment writ large. Employment-distressed communities have received a far greater share of strategic investment dollars than overall non-residential private fixed investment (PFI). Due to larger year-to-year differences in PFI, we compare 2021-2022 strategic sector investments against 2021-2022 total non-residential PFI and PFI in structures (e.g., newly constructed facilities, commercial properties, and other supportive infrastructure) to provide a direct comparison.

Employment-distressed counties represented 7% of total non-residential PFI and 10% of PFI in structures in 2021-2022, and received 16% of strategic sector investments in that time frame. This means strategic sector investments are flowing to employment-distressed counties at levels 2.1 and 1.7 times that of total non-residential PFI and PFI in structures, respectively.



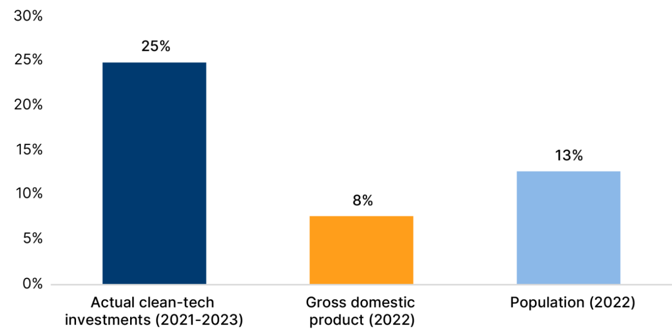
Map 1: Employment-distressed communities are disproportionately benefitting from private strategic sector investments

Strategic sector investments in non-distressed and employment-distressed counties, 2021-2023

Source: Brookings Metro and MIT CEEPR analysis of Clean Investment Monitor, White House Investing in America database, Bureau of Economic Analysis, and U.S. Census Bureau data.

Actual investments in the clean economy are also outpacing GDP and population share in employment-distressed counties

Actual spending on clean economy investments versus economic output and population in employment-distressed counties (share of nation), 2021-2023



This trend also represents a departure from the geographic pattern of PFI during the decade between the Great Recession and the COVID-19 recession. On average, distressed counties received 8% of total non-residential PFI and 12% of PFI in structures while producing 7% of national GDP during the previous recovery (2010 to 2020). During the COVID-19 economic recovery (2021 to 2022), these counties received 16% of strategic sector investments—two and 1.3 times the previous recovery's share of non-residential PFI and PFI in structures, respectively, and 2.3 times their level of GDP.

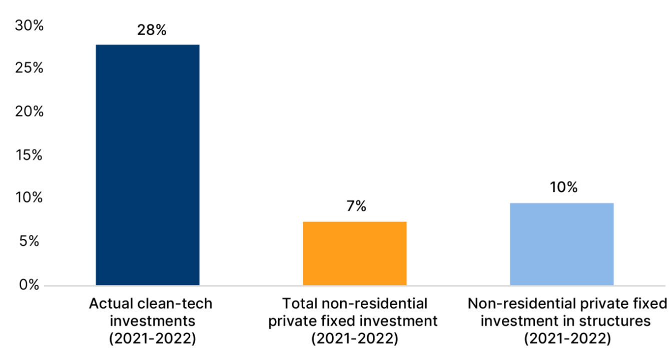
Employment-distressed communities received an even higher share of actual investment in clean technology

The previous finding tracks announced investments, which serves as a useful leading indicator, but is subject to the risk that actual investments do not materialize. Data from the Clean Investment Monitor reveals that actual clean technology investments extend the trends of announced investments across strategic sectors, with employment-distressed communities receiving an even greater share of actual clean-tech investments made thus far.

Since 2021, $26.6 billion of clean-tech investments have translated into real spending. One in four of these dollars ($6.6 billion) has reached employment-distressed communities, compared to 16% of overall strategic sector investments. Employment-distressed communities received actual clean-tech investment at 3.2 and two times their GDP and population levels, respectively.

Employment-distressed counties have received much higher shares of actual clean economy investment than traditional private fixed investment

Actual spending on clean economy investments versus non-residential private fixed investment (share of nation), 2021-2022



A significantly higher share of actual clean-tech investment went to employment-distressed communities compared to private investment writ large. Actual clean-tech investment in employment-distressed communities was nearly four times total PFI to those communities, and 2.9 times structures investment specifically.

Employment-distressed counties that received a strategic sector investment have higher advanced industry employment shares than non-recipient distressed counties

Prior Brookings Metro research identified a set of "advanced industries" that are critical to U.S. innovation, productivity, and prosperity. These industries—which include auto manufacturing, pharmaceuticals, clean energy generation, and digital services—are "advanced" because they invest heavily in research and development and employ large numbers of STEM workers. Together, these high-value, export-intensive industries account for 90% of the nation's private sector R&D spending; saw their wages grow 1.7 times faster than non-advanced sectors between 2001 and 2020; and in 2022 accounted for 7 million decent-paying jobs that typically did not require a bachelor's degree.

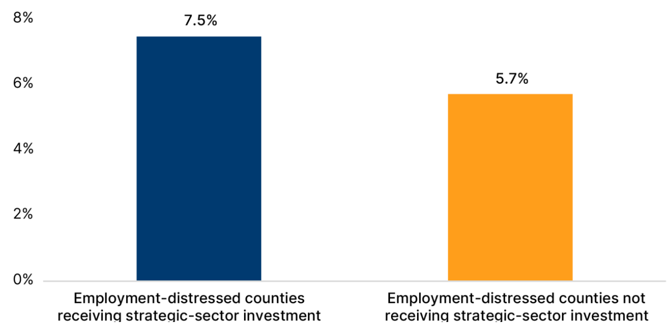
The presence of these industries in a local economy often signals unique capabilities for advanced production. It is not surprising, then, that employment-distressed counties that have received a strategic sector investment have a share of local employment in advanced industries that is on average 31% higher than non-recipient distressed counties. Among the 70 recipient employment-distressed counties, the local share of advanced industries employment is 7.5%, compared to 5.7% in non-recipient distressed counties.

Notably, there are about 250 employment-distressed counties with at least 7.5% of their local employment in advanced industries which have not yet received a strategic sector investment. Thus, the presence of advanced industries is by no means the only factor that motivates investment decisions, but this marker may reveal a much broader set of distressed counties with the necessary conditions to support a strategic sector investment in the coming years.

For example, Putnam County, Ind. and Gila County, Ariz. are employment-distressed counties that have not yet received a private strategic sector investment, but have a similar share of advanced industry employment as those that have. And like many others, these employment-distressed counties share a regional talent pool with other planned private investments—better preparing them to build and expand their activity in advanced industry supply chains. So, while about 7% of employment-distressed counties have received a strategic sector investment since 2021, an additional 24% of employment-distressed counties may be attractive to investors according to this predictive indicator.

Employment-distressed counties receiving a strategic sector investment have higher shares of advanced industry employment than non-recipient employment-distressed counties

Share of advanced industry employment in employment-distressed counties, strategic sector recipients versus non-recipients (2021-2023)



Strategic sector investments in employment-distressed counties have disproportionately flowed to smaller population centers

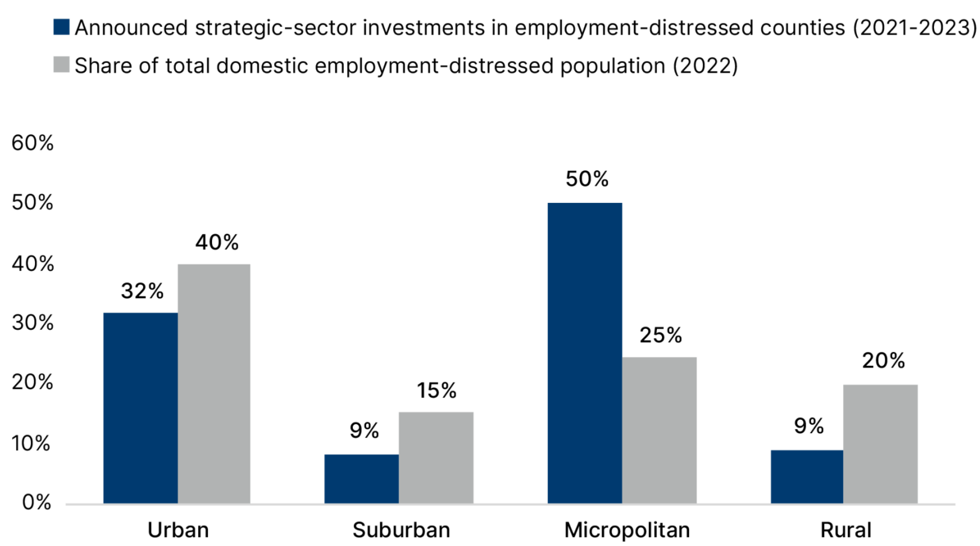
Regions that have at least one urban area with a population of 50,000 or higher are defined as "metropolitan statistical areas," while regions that have at least one urban area with a population between 10,000 and 50,000 are defined as "micropolitan statistical areas." Across employment-distressed areas, counties located in micropolitan statistical areas have proven especially attractive to investors and manufacturers. Micropolitan areas account for approximately 25% of the nation's total employment-distressed population, but these areas have received 50% of all announced strategic sector investments in employment-distressed counties since 2021.

The trend toward micropolitan areas is important for both understanding investor priorities around site selection and for identifying other employment-distressed counties that may be prime candidates for future investment. The tremendous scale required to manufacture electric vehicles, batteries, and semiconductors likely means that companies are seeking the plentiful land and build-ready sites available in many micropolitan regions, with the assumption that they can draw on a larger workforce living in nearby metropolitan areas. One example is Haywood County, Tenn.—an employment-distressed micropolitan county adjacent to the Jackson, Tenn. metro area that has a high share of advanced industry employment, and where Ford and SK On have partnered to build a new electric vehicle manufacturing plant on a 2.3-square-mile plot of land. Similarly, in Matagorda County, Texas—a micropolitan county on the outskirts of Houston—HIF Global is investing over $6 billion to build the world's largest e-fuels facility, which will capture over 2 million tons of carbon dioxide per year when fully operational.

Strategic sector investments are charting a different geographic course, but intentional strategies are still needed

The previous three years of data indicate that after decades of economic divergence, strategic sector investment patterns are including more places that have historically been left out of economic growth. Employment-distressed communities are receiving an outsized share of strategic sector investments compared to their share of economic activity, population, and overall private investment from the last few years and investment in the last decade. And the map is not yet finished: There are hundreds of distressed counties with assets similar to those that have attracted investment and have not yet been targeted.

This suggests that the benefits of a national industrial strategy can reach people and communities that have historically been excluded from economic opportunity—a trend that bodes well for the entire country. Economist Timothy J. Bartik's research has shown that there are disproportionate benefits to the national economy when jobs are created in communities with low employment rates.



Employment-distressed counties in micropolitan areas are receiving twice as many strategic sector investments than their share of the nation's total employment-distressed county population

Strategic sector investments in employment-distressed counties (by county urbanicity), 2021-2023

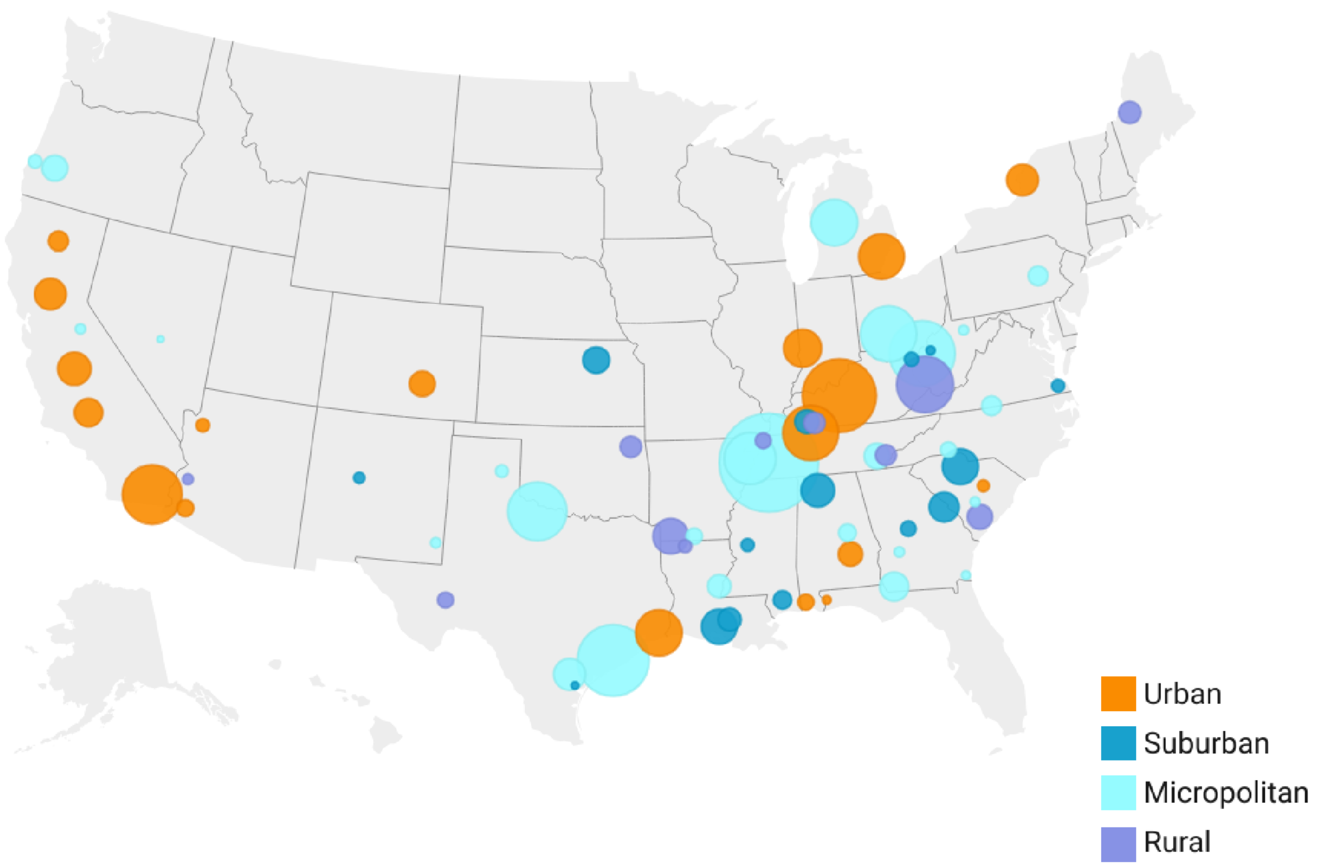
Acknowledging this early progress, the path from private investment into broadly shared and inclusive economic opportunity is not automatic—it requires intentional strategies to connect local workers and businesses to these new investments. Policies that create these "local linkages"—in the language of economic development—are crucial to ensuring that residents benefit from the investment surge. Absent intentionality and inclusion, the benefits of these strategic sector investments may not extend to local workers and communities.

Federal place-based policies—such as the Regional Technology and Innovation Hubs program and the Recomplete Pilot Program—offer the kinds of flexible support for government, education, and community institutions to partner with the private sector to drive inclusive economic growth at the local level. But while these programs are carefully designed and grounded in hard evidence about what works, Congress has not yet adequately funded them. In the shorthand of lawmaking, they have been "authorized"—a big step forward, but with limited funds "appropriated" to them relative to their clear potential for economic revitalization and innovation in communities that have long struggled.

In the absence of adequate federal funding, local, state, and philanthropic investors can also provide support to local communities. Indeed, all levels of our federalist system will need to align resources, capacity, and political will to make the most of this strategic sector investment surge.

Acknowledgment

This commentary was published in partnership with Brookings Metro and the MIT Center for Energy and Environmental Policy Research.



Map 2: Manufacturers have flocked to micropolitan regions when making strategic sector investments in employment-distressed counties

Strategic sector investments in employment-distressed counties (by county urbanicity), 2021-2023

Source: Brookings Metro and MIT CEEPR analysis of Clean Investment Monitor, White House Investing in America database, Bureau of Economic Analysis, Office of Management and Budget, National Center for Health Statistics, and U.S. Census Bureau data. Locations are approximate.

Joseph Parilla, Glencora Haskins, Lily Bermel, Lisa Hansmann, Mark Muro, Ryan Cummings, and Brian Deese (2024), "Research Commentary: Strategic Sector Investments are Poised to Benefit Distressed US Counties", CEEPR RC-2024-02, MIT, February 2024.

Robyn Meeks, Jacquelyn Pless, and Zhenxuan Wang (2023), "Can Digitalization Improve Public Services? Evidence from Innovation in Energy Management", CEEPR WP-2023-22, MIT, December 2023. For references cited in this story, full bibliographical information can be found in the Working Paper.

Research.

Can Digitalization Improve Public Services? Evidence from Innovation in Energy Management

By: Robyn Meeks, Jacquelyn Pless, and Zhenxuan Wang

Economic activity—from business and industrial operations to healthcare and transportation—hinges on having a reliable supply of electricity. However, electricity grids in many countries are aging and increasingly susceptible to disruptions. Power outages in the United States alone cost between $28 and $169 billion annually (ASCE, 2021). Although severe weather is a common cause, other factors such as equipment failure and utility practices affect quality of service as well (EIA, 2021). The ability to manage the grid more efficiently will be especially important for ensuring grid resilience moving forward. In an effort to mitigate climate change, deployment of renewable energy sources with variable output and electrification of end-use products are accelerating. These shifting dynamics are intensifying demands on the system and introducing new challenges for utilities.

Digitalization is frequently discussed as being an important part of the solution, as "smart grid" technologies can, in theory, help monitor and optimize operations and improve system flexibility (Joskow, 2012). Advances in data storage, computation, and transmission are transforming most industries, and electricity is no exception. However, despite the hundreds of billions of dollars spent each year globally on modernizing electricity grids (IEA, 2023), whether digitalization delivers on its promises remains contentious.

This paper provides evidence as to how digitalization impacts electricity service provision. We examine the effects of electric utilities' investments in advanced metering infrastructure (AMI) "smart meters" on utility performance and service quality across the U.S. from 2007 through 2017. Utilities historically relied on analog meters that were developed in the 1800s to track electricity consumption, requiring manual in-person readings and providing utilities with sparse, imprecise data. Deployment of AMI accelerated about 15 years ago, though, and the industry is now going through a "digital revolution." Approximately 119 million smart meters were installed in the U.S. as of 2022 (EIA, 2022).

Smart meters provide real-time consumption and power quality data that can help utilities improve performance by reducing operational costs and enhancing billing accuracy, load management, and system monitoring. They also can improve reliability if utilities use the information on power outage location to restore power faster. There even is potential for reducing outage frequency. Yet, although experts agree on the need for significant grid investment—and policymakers carved out $13 billion for grid modernization in the 2022 Infrastructure Investment and Jobs Act—the effects of smart meters on service provision have been under-studied. To the best of our knowledge, we are the first to examine how utilities use these digital technologies and the effects on system performance and service quality.

We start by examining the effects of smart meters on electricity losses and sales, two outcomes that capture multiple aspects of utility performance. Electricity losses—the difference between power supplied to the distribution system and that for which customers are billed—translate into costs for utilities. Given that line losses increase exponentially when the grid is constrained, better load management can reduce losses. Losses also increase when voltage fluctuates or equipment ages. This is a complex relationship, as power quality and reliability can both contribute to, and be exacerbated by high losses.

Sales refer to the amount of electricity for which customers are billed. Perhaps counterintuitively, both increases and decreases in sales could signal performance improvements. Sales could decrease if customers use smart meter data to reduce consumption (and thus their electricity bills). Consumption changes also could help utilities with load management. At the same time, given consumption measurement was subject to human error with older technology, an increase in sales could reflect improved billing accuracy and processes. Furthermore, sales could increase if utilities use AMI to address bill non-payment and electricity theft, benefits that are commonly reported by utilities (U.S. DOE, 2016). Finally, sales may increase if a utility's customer base grows, which may occur if AMI attracts new customers given the additional products that it enables.

We find that smart meter deployment improves utility performance in multiple ways. First, on average, losses per unit sold (henceforth "losses per sale") decrease by 3.6% relative to the pre-treatment mean. This efficiency improvement occurs through a 5.9% decrease in total losses as well as a 1.2% increase in total sales. Losses per sale decrease by 7.7% for utilities in the highest quartile of the pre-treatment losses per sale distribution. The decrease in total losses on average grows to approximately 7.6% after three years, which is consistent with utilities needing time to learn and to invest in organizational capital, such as new business processes and worker capabilities, for the performance benefits to materialize.

Next, we explore whether the sales increase is driven by sales per customer or number of customers. We find that both contribute. The former is consistent with more accurate billing and utilities leveraging the automated data to improve their operations and processes, while the latter suggests that utilities' customer bases grow.

To further probe whether utilities make operational and energy management adjustments with AMI adoption, we examine the composition of the utility sector's local workforce. Integrating smart technologies and leveraging their capabilities to improve decision-making requires workers with different skills relative to those required with the traditional meters. Using the Occupational Employment and Wage Statistics data provided by the U.S. Bureau of Labor Statistics, we indeed find a reduction in meter readers. Utilities also appear to hire more "quants"—individuals like computer scientists who are equipped with the skills to analyze data and build energy system optimization models—which is consistent with utilities making organizational investments that can enhance the benefits of digitalization.

We use data on power outages in Texas to examine whether reliability improves, which also can provide insight on whether utilities use smart meters to respond to outages faster or avoid them altogether. Following smart meter deployment, outage duration decreases by 5.5%, suggesting that utilities indeed use the technology to restore power faster. However, we find no reduction in outage frequency. This suggests that, although energy management improvements—such as enhanced system monitoring and load management—can enhance performance via reductions in losses and power outage duration, other solutions are needed to reduce the number of outages.

Overall, our findings indicate that digitalization can enhance service quality and that energy management improvements are at play. This, in turn, implies that realizing the benefits of digitalization may depend on organizational capital (e.g., business processes, worker skills, etc.). To explore this further, we examine the heterogeneity in effects across utility ownership structure. Like many other public services, electricity providers can be either government- or privately-owned, which can result in different managerial incentives and constraints that may impact performance (e.g., profit-maximization versus social objectives) (Hart, Shleifer and Vishny, 1997; Shleifer, 1998; Duggan, 2000). We find that the effects on losses and sales are driven entirely by government-owned utilities as opposed to those that are investor-owned or operate as cooperatives. Differences in other observable characteristics, like pre-treatment size and performance, do not account for the heterogeneity. These results are consistent with how organizational factors that generate incentives for improving energy management and quality of service may contribute to whether the benefits of digitalization materialize.

Research examining how some digital technologies impact firm performance dates back to the 1990s and spans many fields of economics (see Draca, Sadun and Van Reenen (2009) and Goldfarb and Tucker (2019) for reviews). However, much less has been known about the effects of digitization on organizations providing public services, besides in healthcare (see Bronsoler, Doyle and Van Reenen (2022) for a review). Our study helps narrow this gap through our examination of smart meter deployment in the U.S. We found that digitalization indeed enhanced service provision and the effects appear to be driven by improvements to energy management—such as through the implementation of automated billing processes and better system monitoring capabilities—and the effects vary by ownership structure. Taken together, the findings suggest that digitalization can be a tool for improving public services, but the benefits may hinge upon organizational capital and managerial incentives.

—Summary by Trinity White

Faculty Profile.

A Delicate Dance

By: Deborah Halber | MIT Energy Initiative

Professor of applied economics Catherine Wolfram balances global energy demands and the pressing need for decarbonization.

Professor Catherine Wolfram, an economist in the MIT Sloan School of Management, looks for ways to decarbonize global energy systems while recognizing that energy drives economic development, especially in the developing world.

Photo credit: Tim Correira/Caitlin Cunningham Photography LLC.

In early 2022, economist Catherine Wolfram was at her desk in the U.S. Treasury building. She could see the east wing of the White House, just steps away.

Russia had just invaded Ukraine, and Wolfram was thinking about Russia, oil, and sanctions. She and her colleagues had been tasked with figuring out how to restrict the revenues that Russia was using to fuel its brutal war while keeping Russian oil available and affordable to the countries that depended on it.

Now the William F. Pounds Professor of Energy Economics at MIT, Wolfram was on leave from academia to serve as deputy assistant secretary for climate and energy economics.

Working for Treasury Secretary Janet L. Yellen, Wolfram and her colleagues developed dozens of models and forecasts and projections. It struck her, she said later, that "huge decisions [affecting the global economy] would be made on the basis of spreadsheets that I was helping create." Wolfram composed a memo to the Biden administration and hoped her projections would pan out the way she believed they would.

Tackling conundrums that weigh competing, sometimes contradictory, interests has defined much of Wolfram's career.

Wolfram specializes in the economics of energy markets. She looks at ways to decarbonize global energy systems while recognizing that energy drives economic development, especially in the developing world.

"The way we're currently making energy is contributing to climate change. There's a delicate dance we have to do to make sure that we treat this important industry carefully, but also transform it rapidly to a cleaner, decarbonized system," she says.

Economists as influencers

While Wolfram was growing up in a suburb of St. Paul, Minnesota, her father was a law professor and her mother taught English as a second language. Her mother helped spawn Wolfram's interest in other cultures and her love of travel, but it was an experience closer to home that sparked her awareness of the effect of human activities on the state of the planet.

Minnesota's nickname is "Land of 10,000 Lakes." Wolfram remembers swimming in a nearby lake sometimes covered by a thick sludge of algae. "Thinking back on it, it must've had to do with fertilizer runoff," she says. "That was probably the first thing that made me think about the environment and policy."

In high school, Wolfram liked "the fact that you could use math to understand the world. I also was interested in the types of questions about human behavior that economists were thinking about.

"I definitely think economics is good at sussing out how different actors are likely to react to a particular policy and then designing policies with that in mind."

After receiving a bachelor's degree in economics from Harvard University in 1989, Wolfram worked with a Massachusetts agency that governed rate hikes for utilities. Seeing its reliance on research, she says, illuminated the role academics could play in policy setting. It made her think she could make a difference from within academia.

While pursuing a PhD in economics from MIT, Wolfram counted Paul L. Joskow, the Elizabeth and James Killian Professor of Economics and former director of the MIT Center for Energy and Environmental Policy Research, and Nancy L. Rose, the Charles P. Kindleberger Professor of Applied Economics, among her mentors and influencers.

After spending 1996 to 2000 as an assistant professor of economics at Harvard, she joined the faculty at the Haas School of Business at the University of California at Berkeley.

At Berkeley, it struck Wolfram that while she labored over ways to marginally boost the energy efficiency of U.S. power plants, the economies of China and India were growing rapidly, with a corresponding growth in energy use and carbon dioxide emissions. "It hit home that to understand the climate issue, I needed to understand energy demand in the developing world," she says.

The problem was that the developing world didn't always offer up the kind of neatly packaged, comprehensive data economists relied on. She wondered if, by relying on readily accessible data, the field was looking under the lamppost — while losing sight of what the rest of the street looked like.

To make up for a lack of available data on the state of electrification in sub-Saharan Africa, for instance, Wolfram developed and administered surveys to individual, remote rural households using on-the-ground field teams.

Her results suggested that in the world's poorest countries, the challenges involved in expanding the grid in rural areas should be weighed against potentially greater economic and social returns on investments in the transportation, education, or health sectors.

Taking the lead

Within months of Wolfram's memo to the Biden administration, leaders of the intergovernmental political forum Group of Seven (G7) agreed to the price cap. Tankers from coalition countries would only transport Russian crude sold at or below the price cap level, initially set at $60 per barrel.

"A price cap was not something that had ever been done before," Wolfram says. "In some ways, we were making it up out of whole cloth. It was exciting to see that I wrote one of the original memos about it, and then literally three-and-a-half months later, the G7 was making an announcement.

"As economists and as policymakers, we must set the parameters and get the incentives right. The price cap was basically asking developing countries to buy cheap oil, which was consistent with their incentives."

In May 2023, the U.S. Department of the Treasury reported that despite widespread initial skepticism about the price cap, market participants and geopolitical analysts believe it is accomplishing its goals of restricting Russia's oil revenues while maintaining the supply of Russian oil and keeping energy costs in check for consumers and businesses around the world.

Wolfram held the U.S. Treasury post from March 2021 to October 2022 while on leave from UC Berkeley. In July 2023, she joined MIT Sloan School of Management partly to be geographically closer to the policymakers of the nation's capital. She's also excited about the work taking place elsewhere at the Institute to stay ahead of climate change.

Her time in D.C. was eye-opening, particularly in terms of the leadership power of the United States. She worries that the United States is falling prey to "lost opportunities" in terms of addressing climate change. "We were showing real leadership on the price cap, and if we could only do that on climate, I think we could make faster inroads on a global agreement," she says.

Now focused on structuring global agreements in energy policy among developed and developing countries, she's considering how the United States can take advantage of its position as a world leader. "We need to be thinking about how what we do in the U.S. affects the rest of the world from a climate perspective. We can't go it alone.

"The U.S. needs to be more aligned with the European Union, Canada, and Japan to try to find areas where we're taking a common approach to addressing climate change," she says. She will touch on some of those areas in the class she will teach in spring 2024 titled "Climate and Energy in the Global Economy," offered through MIT Sloan.

Looking ahead, she says, "I'm a techno optimist. I believe in human innovation. I'm optimistic that we'll find ways to live with climate change and, hopefully, ways to minimize it."

—This article appears in the Winter 2024 *issue of* Energy Futures, *the magazine of the MIT Energy Initiative.*

MIT Sloan to Launch New Climate Policy Center with $25 Million Investment

As part of the new Climate Project at MIT, the center will create and strengthen connections between leading climate researchers and policymakers

By: MIT Sloan Office of Communications

Cambridge, MA, March 06, 2024 —

The MIT Sloan School of Management is launching a new center aimed at providing evidence-based climate policy research to help inform and support local, state, national, and international policymakers. Jump-started by a $25 million investment by MIT Sloan as part of an emerging MIT-wide effort, the MIT Climate Policy Center will engage on a broad set of climate policy issues.

Christopher Knittel, the George P. Shultz Professor of Energy Economics at MIT Sloan, will serve as the center's faculty director. "It is critical that universities contribute meaningfully to these conversations, ensuring research is accessible to decision-makers on an accelerated time scale," said Knittel. "We are proud to introduce the MIT Climate Policy Center, because we know climate change is an urgent problem we can address if we focus our resources and expertise on it in a systematic way." In addition to serving as faculty director of the new center, Knittel will be named associate dean at MIT Sloan, effective July 1.

The center will connect current and future climate research to policy, measuring the impact and implications of a variety of technologies on the climate system as a whole, both regionally and across the globe. It

will explore what climate goals can be met with existing technology, what relevant new technologies are on the horizon, how best to bring those technologies to fruition, and how to make them viable in the marketplace.

The MIT Climate Policy Center will:

- Collaborate with existing climate efforts across MIT, working with all faculty, departments, centers, and initiatives engaged in climate policy research and outreach.
- Forge ongoing relationships between MIT and relevant policymakers.
- Direct new policy-oriented research efforts to serve as a resource for policymakers who wish to advance evidence-based climate policy.
- Be a central resource for students, providing them with opportunities to engage more deeply with, and to affect, public policy.
- Work closely with the MIT Washington Office on matters of federal policy. The center is part of the new Climate Project at MIT, which aims to develop and deliver practical climate solutions at scale as quickly as possible. With an initial commitment of $50 million in Institute resources, the new project is the largest direct investment the Institute has ever made in funding climate work, and just the beginning of a far more ambitious effort.

Christopher R. Knittel, the George P. Shultz Professor of Energy Economics, will lead the new MIT Climate Policy Center and will be named an Associate Dean at the MIT Sloan School of Management, effective July 1, 2024.

"After extensive consultation with more than 150 faculty and senior researchers across the Institute – and building on the strengths of Fast Forward: MIT's Climate Action Plan for the Decade, issued in 2021 – Vice Provost Richard Lester has led us in framing a new approach: the Climate Project at MIT," MIT President Sally Kornbluth wrote in a message to the MIT community on February 8, 2024. "Representing a compelling new strategy for accelerated, university-led innovation, the Climate Project at MIT will focus our community's talent and resources on solving critical climate problems with all possible speed — and will connect us with a range of partners to deliver those technological, behavioral and policy solutions to the world," she continued.

International, federal, state and local policymakers will be able to contact the center to identify existing research or to begin work with world-class researchers to develop targeted projects that could inform the development of new rules, regulations, or legislation.

"I'm grateful for the incredible collaboration with many colleagues across the Institute and MIT Sloan in this process — such as efforts by David Goldston, who leads the MIT Washington Office, Bethany Patten, director of policy and engagement at the Sustainability Initiative at MIT Sloan, and especially for the vision and leadership of former MIT Sloan Dean David Schmittlein — all of whom contributed to the planning, advocacy, and engagement that helped make this center a reality," Knittel said. "The MIT Climate Policy Center will enable our faculty and our students to fulfill MIT Sloan's mission to 'develop principled, innovative leaders who improve the world' even more directly by producing research that will shape policies to combat climate change."

"The MIT Climate Policy Center will enable our faculty and our students to fulfill MIT Sloan's mission to develop principled, innovative leaders who improve the world."

—Christopher R. Knittel

Research.

Understanding the Future of Critical Raw Materials for the Energy Transition: SVAR Models for the U.S. Market

By: Ilenia Gaia Romani and Chiara Casoli

The energy transition stands as a cornerstone in fighting climate change and reaching net-zero emissions by 2050. This challenge requires the development and adoption of new technologies for energy generation, which will lead to a substantial increase in demand for critical raw materials (IEA, 2021).

Critical raw materials are becoming rapidly dominant in the development of different technologies and several countries have already studied plans to secure access to them. Many of these resources are concentrated in few geographical areas, often subject to geopolitical tensions and mostly in developing countries. Governments recognize the significance of mineral requirements for the energy transition and are prioritizing the strengthening of domestic supply chains due to the increasing dependence on foreign sources for critical minerals. Two notable policies for boosting access to clean technologies are the U.S. 2022 Inflation Reduction Act (IRA), affecting all of North America with energy and climate subsidies, and the European 2023 Critical Raw Materials Act, aimed at increasing and diversifying the EU's critical raw materials supply. In the U.S., the White House has favored an expansion of domestic mining, production, processing, and recycling of critical minerals and materials.

This study aims to assess the role of the Inflation Reduction Act and other U.S. policies strategic for boosting the minerals' domestic production in terms of future price patterns of some critical raw materials. In particular, we focus on a selection of battery minerals, namely cobalt, lithium and nickel. These materials are key ingredients for the energy transition, as they are extensively used in rechargeable lithium-ion batteries, and are strategic for the development of electric vehicles (EVs) and grid-scale energy storage. Given their importance, they are included in the U.S. classification of critical minerals by the U.S. Geological Survey (USGS) and in the Inflation Reduction Act.

We build a Structural VAR model (SVAR) for each mineral market of interest and disentangle the role of different shocks on mineral fundamentals. Specifically, by identifying four separate structural shocks, distinguishing between aggregate supply and demand shocks, concerning the whole U.S. business cycle, and between mineral-specific supply and demand shocks, which are driven solely by the commodities market fundamentals, we are able to model the energy-transition policies as a mix of these shocks.

Additionally, our econometric model is particularly suitable for the evaluation of U.S. policies of the energy transition. In fact, we also conduct a structural forecast exercise to quantify the effects of selected energy transition-related U.S. policies on the evolution of prices in battery minerals markets. To do so, we condition forecasts of the selected minerals prices on different future trajectories of structural shocks up to 2030. The comparison of the different outcomes provides a useful indication of the range of possible future price evolution under different policy mixes.

In order to build the hypothetical sequences of future paths of demand and supply shocks up to 2030, we employ thought experiments, backed as much as possible by empirical evidence. Specifically, we ask ourselves what would happen to mineral prices if mineral demand shocks impacted prices themselves more or less strongly, and supply shocks increased domestic minerals' production just enough to alleviate import dependency, versus the IRA-induced stronger increase in production.

We build specific scenarios to address those questions, and feed them into our conditional forecast equation as future flow shocks (of supply or demand), while setting all other future structural shocks equal to their zero expected value. The cases we consider are listed below.

a. Historical demand increase: to reconstruct the energy transition dynamics leading to positive mineral-specific demand shocks, we select the sequence of shocks of the years 2010-2015 and suppose that the same path will continue in the following years.

b. Higher demand increase: we assume that the biggest demand increase will happen in the following two years, hence we modify the previous scenario by imposing a higher increase in 2023 and 2024, setting their growth rates equal to the average of the last five years' price growth.

c. Ambitious supply increase: we compute the expected increase in domestic minerals' production driven by government funding. In order to map the U.S. extraction and processing projects of cobalt, lithium and nickel that will be developed in the years to come, we review their development studies and releases. We compile a list of these projects, which highlights the target year and the targeted annual production. By cumulating each mineral's annual exceptional production across projects, we calibrate the expected supply shock matching with the desired production driven by public policies up to 2030.

d. Lower supply increase: we conjecture the expected increase in U.S. production driven by the government's stated goal of import independency. Official U.S. documents define import reliance as imports (M) being greater than 50 percent of annual consumption (C), for most of the minerals designated as critical, including cobalt, lithium and nickel. Considering this approximation: $C = P + (M - X)$ (consumption equals the sum of domestic production and net imports) and that imports cannot exceed 50 percent of the consumption, we calculate the new production capacity necessary to maintain the same level of consumption $P^* = C - (M^* - X)$, with $M^* = C/2$. By doing so, we are able to compute an approximation of the production increase which would allow the U.S. to stop being import reliant. We therefore compute a supply shock compatible with this production approximation.

Figure 1 displays the historical price series along with the structural forecasts up to 2030 for the prices of the three minerals. The left panel presents the projections based on individual scenarios, namely (a) historical demand increase, (b) higher demand increase, (c) increasing production driven by U.S. government policies such as the IRA, and (d) increasing production driven by the goal of achieving import independence. Despite considering these scenarios in isolation presents an interesting picture, a more realistic situation would involve a combination of supply and demand forces. For instance, a significant supply increase without a corresponding demand request is unlikely. For this reason, the right panel of Figure 1 displays combinations of demand and supply scenarios together.

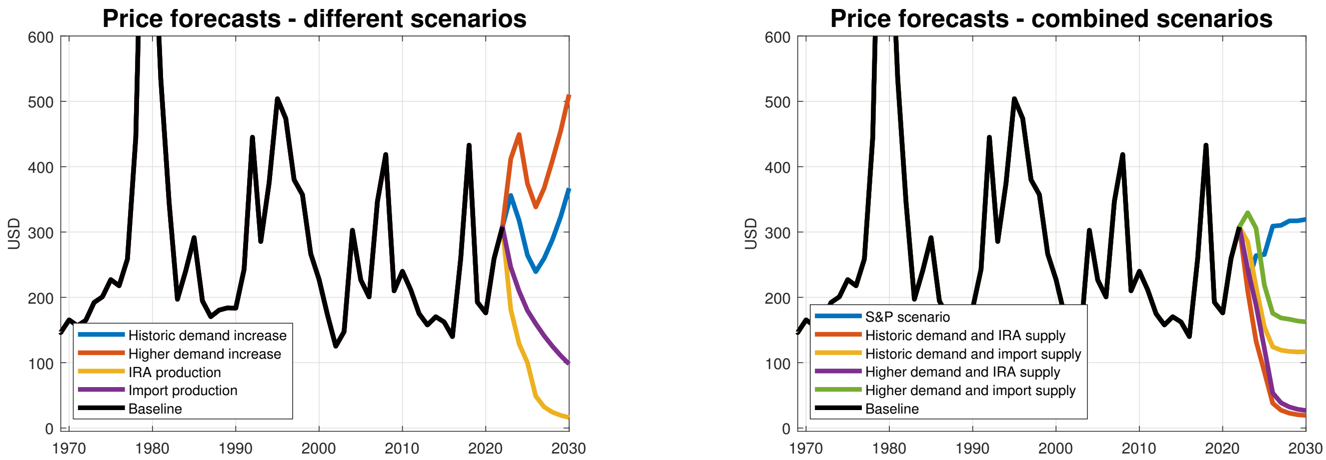
In the case of the cobalt market, supply rather than demand scenarios have the most significant effect on price, which, as a consequence, keep decreasing quite steadily, especially with IRA-driven production.

Lithium price, already peaking in 2022, has an extended peak in 2023. This is particularly pronounced in the case of the higher demand and IRA-driven supply scenario, and reverts to more credible levels starting from them subsequent year. This is likely explained by the fact that, according to the funded projects, additional lithium domestic production will not start until 2024.

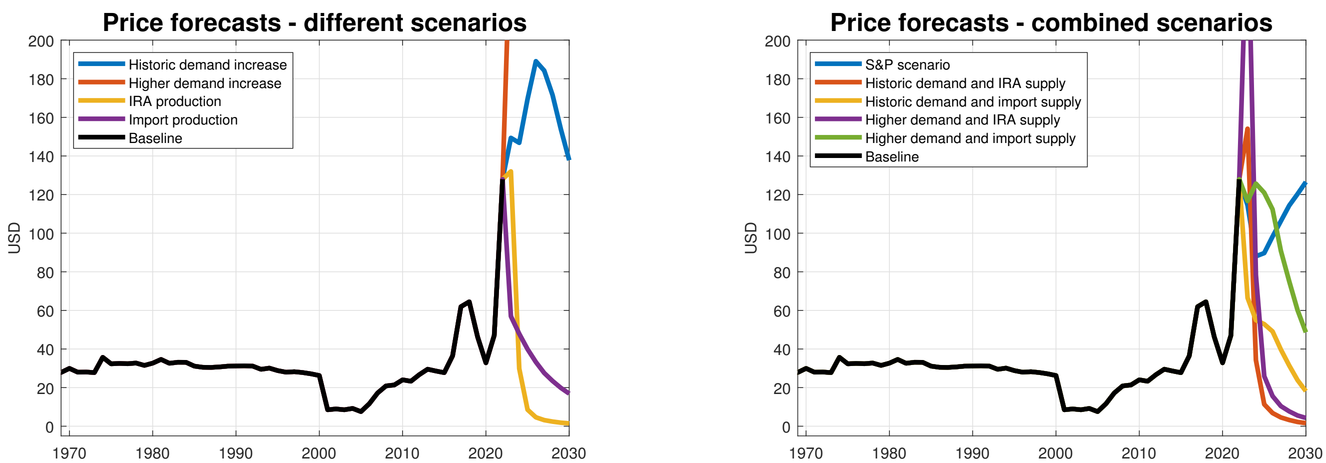
In contrast, the structural forecast of nickel prices is only moderately influenced by supply scenarios. Given that the additional investment in

Ilenia Gaia Romani and Chiara Casoli (2024), "Understanding the Future of Critical Raw Materials for the Energy Transition: SVAR Models for the U.S. Market", CEEPR WP-2024-05, MIT, March 2024.

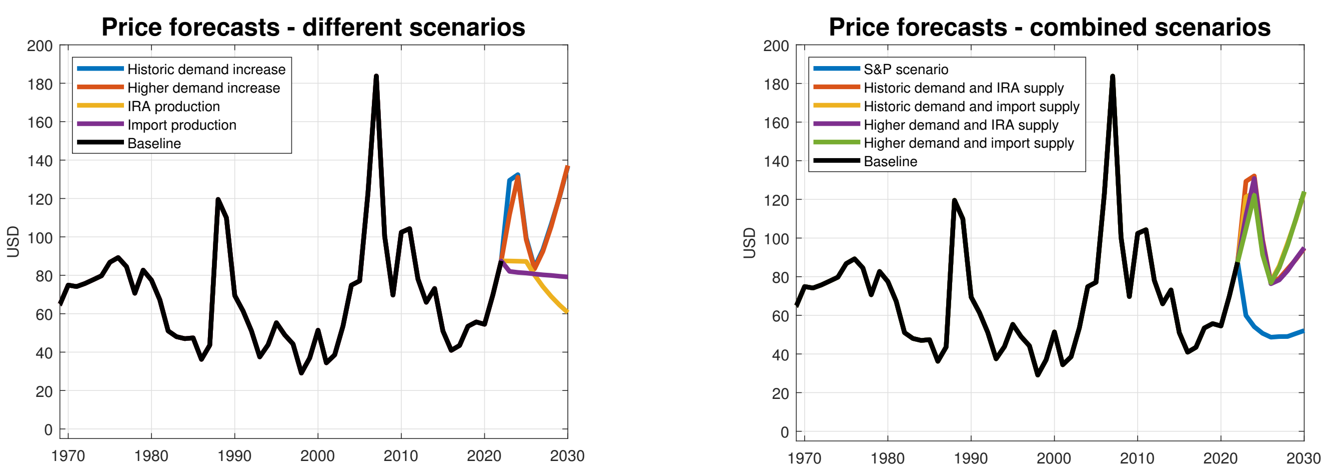
For references cited in this story, full bibliographical information can be found in the Working Paper listed above.



(a) Forecast of colbalt prices, according to individual (left panel) and combined (right panel) scenarios



(a) Forecast of lithium prices, according to individual (left panel) and combined (right panel) scenarios



(a) Forecast of nickel prices, according to individual (left panel) and combined (right panel) scenarios

Figure 1. Forecast of minerals' prices (USD/t) up to 2030 according to different scenarios

the domestic production of the mineral is quite restricted in both the IRA- and import-independency-driven production scenarios, the nickel price exhibits a path which follows more the demand-side scenarios.

Our research yields two key takeaways. First, different mineral markets exhibit distinct dynamics, emphasizing the need to treat them as separate entities rather than as a homogeneous group. Second, different policy combinations lead to heterogeneous price patterns over the forthcoming years. Our price forecasts are, by definition, conditional on the chosen scenarios. This follows from the definition of a structural forecast, which can be framed in the form of: "what would happen, if...?" and therefore does not provide the most likely outcome. For example, if the U.S. experiences an increase in demand that follows the historical trends, coupled by the ambitious production boost driven by U.S. public investments, prices of cobalt and lithium will decrease steadily. Conversely, the nickel price is expected to remain high. This reflects the target of the selected U.S. policies, focused on strengthening the domestic production of cobalt and lithium, whereas less effort is devoted to nickel market expansion.

More research effort should be invested around the development of country-specific scenarios. In fact, most of the studies – including IEA technical reports – provide demand (and to a lesser extent, supply) estimations only at the global level (Calvo and Valero, 2022; Hund et al., 2023). Moreover, we acknowledge the importance of focusing on conditional forecasts targeting specific national policies, thus providing a useful tool for the evaluation of government strategies.

As the U.S. navigates the path toward cleaner energy, the insights around price dynamics gained from this study could provide valuable guidance for policymakers and industry stakeholders.

Research.

Bridging the Divide: Assessing the Viability of International Cooperation on Border Carbon Adjustments

By: Michael Mehling, Harro van Asselt, Susanne Droege, Kasturi Das, and Catherine Hall

Trade-Climate Cooperation at the Crossroads

Recent years have witnessed the emergence of a broad range of multilateral, plurilateral and bilateral cooperative initiatives at the intersection of international trade and climate change. An encouraging trend, this proliferation reflects increasing awareness of the interconnected nature of international trade and climate change. About a quarter of global carbon dioxide emissions are embedded in the international trade of goods and services, and trade policy can also play a significant role in supporting countries in their efforts to decarbonize and adapt to the impacts of climate change.

Still, these developments are taking place against the wider backdrop of an equally dramatic pivot towards nationalist retrenchment, spurred by populist domestic politics, growing geopolitical tensions, and widespread disenchantment with the unintended effects of globalization on national economies. In response, jurisdictions are increasingly taking recourse to protectionist trade and industrial policies. Many of the protectionist tendencies that underlie the current dynamic of economic retrenchment and fragmentation are mediated by policy strategies that invoke climate ambition and deep decarbonization as both a justification and a central objective, the most contested among them arguably being border carbon adjustments (BCAs).

Border Carbon Adjustments and their Discontents

In a world characterized by unequal carbon constraints, jurisdictions with more stringent climate constraints face the risk of carbon leakage. BCAs have long been discussed as a concrete measure to help address this problem. Still, BCAs can also be adopted for a variety of other reasons, including as a safeguard of the international competitiveness of domestic industries, and to induce trade partners to ramp up their own climate mitigation efforts.

So far, BCAs have proven to be the most controversial measure at the intersection of international trade and climate policy. Reasons include their alleged advancement of "green protectionism" and their potential economic and social impacts on trade partners, particularly those from the Global South that are least responsible for the climate crisis, thereby raising complex normative questions about climate justice and equity.

The EU's Carbon Border Adjustment Mechanism (CBAM) has brought these debates to the forefront of the climate-trade policy discourse. However, the EU CBAM is unlikely to be the last or only BCA, with various jurisdictions contemplating similar measures as they adopt increasingly ambitious climate mitigation policies and pursue other policy objectives, such as improved national security or industrial policy strategies. This broader trend highlights the growing risks associated with uncoordinated proliferation of unilaterally implemented BCAs that reflect divergent approaches to design and implementation, which in turn can translate into greater uncertainty, higher transaction and administrative costs, as well as detrimental impacts on international trade and global efforts to tackle climate change and its impacts.

A new CEEPR Working Paper makes the case for international cooperation on or relating to BCAs and assesses the prospects for such cooperation. The report applies an analytical framework that examines both the "input legitimacy" and "output legitimacy" of international cooperative initiatives. It applies this analytical framework to three emerging models of cooperation relating to BCAs, namely the G7 Climate Club, the transatlantic talks on a Global Arrangement on Sustainable Steel and Aluminium (GASSA), and the Inclusive Forum on Carbon Mitigation Approaches (IFCMA) launched by the Organisation for Economic Co-operation and Development (OECD).

Rationales for International Cooperation on BCAs

International cooperation is not only one of the core principles underpinning the international legal order, including the international climate and trade regimes, but it can also help address some of the adverse impacts potentially associated with BCAs, including the perception of "green protectionism" and risks of tit-for-tat trade retaliation.

International cooperation could further ensure that BCAs become part of broader diplomatic efforts on climate change, taking into account, among other things, the interests and priorities of countries in the Global South that would be adversely affected by BCA implementation. Besides, international cooperation could reduce the risk of exacerbating fragmentation and trade barriers in the global order through the emergence of multiple BCAs, each with their own procedures and requirements.

By targeting traded products, BCAs inherently have an external dimension. In the concrete design of BCAs, potential spillover effects are largely determined by provisions on the geographic scope (i.e., the extent to which countries are exempted), the calculation of the adjustment (e.g., whether and what kind of mitigation policies in third countries are credited), the determination of embedded emissions (e.g., whether based on actual emissions or some kind of default values), and the use of revenues (e.g., whether BCA revenues are recycled back to the affected trading partners). The fact that existing or proposed BCAs differ widely in how they deal with such external dimensions underscores the potential benefits of international cooperation, and highlights ways in which the external dimension of BCAs could promote or facilitate such cooperation.

Analytical Framework

In the Working Paper, two core features of international cooperation are analyzed, namely its inclusiveness and institutional strength, both of which can be linked to an initiative's "input legitimacy" (i.e. the quality of the process through which decisions are made).

The rationale for international cooperation points to different goals that can be pursued with international cooperation on BCAs. In the Working Paper, the authors identify five possible goals, which provide the prism through which to assess the "output legitimacy" of any initiative of international cooperation on BCAs (i.e., how effective it is in achieving certain goals). The five goals identified are:

1. promoting transparency (i.e., sharing information on the design, implementation and effects of BCAs);
2. developing objectives and principles for BCAs (i.e., identifying best practices that could guide future design and implementation);
3. improving comparability by developing methodologies that allow for the comparison of different types of mitigation policies and their effects;
4. promoting harmonization with a view to developing product or MRV standards; and
5. broadly contributing to global climate ambition, by either strengthening domestic or third-country climate policies.

For each of the three initiatives under study, namely the G7 Climate Club, GASSA and IFCMA, the Working Paper discusses the extent to which it can be considered inclusive, as well as its underlying institutional strength based on publicly available documents. In addition, the Working Paper also assesses the propensity of these initiatives to contribute to one or more of the five goals identified in this report.

G7 Climate Club

In 2021, the German G7 presidency called on G7 members to introduce a price on carbon and develop a system with a common BCA over time. However, it quickly became clear that a the prospect of joint carbon price among the G7 members would not secure backing by all members. After extensive negotiations among G7 members, a "Climate Club" was announced in December 2022 and officially launched during the United Nations Climate Conference in Dubai in December 2023, with an interim Secretariat to be hosted by the OECD and the International Energy Agency (IEA). The terms of reference of the initiative list three pillars of cooperation: (1) advancing ambitious and transparent climate change mitigation policies; (2) transforming industries; and (3) boosting international climate cooperation and partnerships.

The G7 Climate Club fares well in terms of inclusiveness, as notwithstanding its origins it is in principle open to all countries, and has indeed seen its membership grow to 37 countries from the developed and developing world. As for its institutional strength, the initiative is not aimed at setting standards, and its future is contingent upon the support of subsequent G7 presidencies.

As far as its contribution to the foregoing goals of international cooperation on BCAs is concerned, its performance is mixed. As the Climate Club does not cooperate on BCAs directly, it may at best contribute toward increasing transparency indirectly through the progress made under the IFCMA, which aims to develop a comprehensive database of different policy approaches and accounting methodologies. This would then inform the Climate Club in case BCAs are included in its work program following future elaboration of its scope and mandate. As for improving comparability, members of the Climate Club signed up to engage in the advancement of comparable methodologies to measure, estimate and collect emissions data, for which again they will rely on the IFCMA. The Climate Club focuses on climate ambition, industrial decarbonization, and voluntary cooperation with developing countries, which can potentially contribute to global climate action, depending on the political priorities of the G7 presidency. Neither the development of shared objectives and principles for BCAs nor promoting harmonization are within the terms of reference of the G7 Climate Club, however.

Global Arrangement on Sustainable Steel and Aluminum (GASSA)

The origins of the GASSA can be traced back to tariffs imposed by the U.S. Administration in 2018, which included tariffs of 25% on steel and 10% on aluminum. In response to these tariffs, the EU retaliated with tariffs on other products. The U.S. tariffs were subsequently challenged at the World Trade Organization (WTO) by both the EU and China. In 2021, with a new U.S. Administration in place, the U.S. and the EU issued a joint statement on steel and aluminium, wherein the EU agreed to suspend its WTO challenge and remove its tariffs while the U.S. introduced a Tariff Rate Quota under which a limited amount of steel from the EU could enter the U.S. market free of duties. The deal also marked the launch of negotiations on a Global Arrangement on Sustainable Steel and Aluminium, with an aim to conclude these negotiations within two years. Negotiations have since entered into a stalemate, however, due to multiple differences in approaches, priorities and domestic political dynamics.

The GASSA aims to address two separate, but related issues, namely what is referred to as "non-market excess capacity", which is an implicit reference to China's heavy subsidization of its steel industry, and the carbon intensity of steel and aluminium production.

In terms of inclusiveness, although the GASSA would be open to "like-minded economies", it is by design envisioned as a forum that excludes China, thereby raising questions about its ability to be truly inclusive. As far as its institutional strength is concerned, the GASSA precludes an assessment since the institutional structure has yet to be agreed.

In terms of its contribution to the five identified goals of international cooperation on BCAs, the GASSA performs rather poorly. It is unlikely to serve as a forum for sharing BCA design and implementation information, and hence unlikely to contribute to increasing transparency about BCAs. It is also unlikely to serve as a forum for developing shared objectives and principles for BCAs; or for improving comparability of individual mitigation policies. Although the technical discussion on methodologies could potentially lead to shared understanding on low-carbon intensity standards in steel and aluminum sectors, promoting such harmonization is going to be challenging. In terms of its potential to contribute to global climate ambition, the role of the GASSA is unclear.

Inclusive Forum on Carbon Mitigation Approaches (IFCMA)

In June 2022, the OECD formally launched a new initiative known as the Inclusive Forum on Carbon Mitigation Approaches. The overall objective of the forum is to help enhance the impact of emission reductions efforts globally, through "data and information sharing, evidence-based mutual learning and inclusive multilateral dialogue". Under the auspices of the IFCMA, technical work will be carried out to assess a diverse range of both price-based and non-price-based policy instruments that have been implemented by countries across the world, through the development and application of a consistent methodology. Importantly, however, the IFCMA does not have cooperation around BCAs as its focus.

In terms of inclusiveness, as it seeks to attract a range of participants that includes both OECD member countries and non-member countries, it scores reasonably well. However, it remains to be seen whether and to what extent OECD member countries determine the direction of the initiative. With respect to institutional strength, it again fares relatively well, as it is hosted by a permanent body, namely the OECD. However, while the OECD generally has the ability to set standards and adopt legally binding decisions through the OECD Council, that is not necessarily the case for the IFCMA, which is explicitly intended to not act as a standard-setting body.

As far as its contribution to the five identified goals of international cooperation on BCAs is concerned, again the IFCMA fares reasonably well. Although the Forum is not focused on increasing transparency around BCAs as such, its remit – which includes taking stock of mitigation policy instruments (and policy packages) and their effects on emissions – is sufficiently broad to include a discussion of BCAs as part of mitigation policy packages. Its work related to data collection and analysis can also help jurisdictions determine whether and to what extent they should credit policy efforts in third countries when designing and implementing BCAs, for instance through bilateral agreements. One of the main areas in which the IFCMA can make a truly meaningful contribution is improved comparability, specifically through the methodologies that it will employ to assess the effectiveness of different carbon mitigation approaches in tackling emissions, as well as through its work on carbon intensity metrics. Although standard-setting is explicitly not a part of the IFCMA's mandates, its technical work could lay the foundation for the development of harmonized standards, thereby indirectly promoting harmonization.

Much depends on the extent to which the methodologies developed on mapping and assessing the effects of mitigation policies find support among the IFCMA membership. Although developing shared objectives and principles for BCAs is not directly within the scope of the IFCMA, it can potentially contribute toward this goal indirectly by facilitating an "inclusive multilateral dialogue", which among other things could possibly deliberate on best practices pertaining to BCAs. As for contributing to global climate ambition, the IFCMA could help indirectly by laying the groundwork for determining what the most optimal and effective policies are for tackling climate change, and shedding light on what role, if any, BCAs can play in policy packages. Although the work of the IFCMA seeks to identify capacity constraints in evaluating climate mitigation policies, the Forum as such does not, however, provide any mechanism for providing (capacity-building or financial) support.

Conclusions and Way Forward

The foregoing analysis suggests that none of the three initiatives discussed emerges as an ideal candidate for international cooperation on BCAs. At the same time, this issue area remains a rapidly evolving context. While it may be too early to anticipate the success of the Climate Club and the IFCMA, the crosscutting and facilitative efforts they are pursuing, such as the collection of data and advancement of common metrics and methodologies, may prepare the ground for more robust long-term cooperation on BCAs, and may also help accommodate a more diverse set of mitigation actions and policy approaches. Additionally, through their transparency and inclusiveness, they may potentially strengthen the legitimacy and acceptance of future cooperative efforts on BCAs.

What the analysis also reveals is a real risk that domestic interests and short-term political priorities will take precedence over the acknowledged benefits of international cooperation, unless any cooperative initiatives are thoroughly aligned with all participating jurisdictions' domestic policy approaches and geopolitical positions. Finding a "landing zone" for international cooperation on BCAs among trading partners with often conflicting domestic contexts and priorities will be challenging, as attested by the recent breakdown of the GASSA negotiations among two partners with broadly aligned interests.

Inevitably, this observation gives rise to the question whether, in the current geopolitical context, there can be any way forward on international cooperation on BCAs. One thing is clear: in one form or another, BCAs are becoming an increasingly relevant part of the evolving climate policy landscape. It may be too soon to anticipate their role going forward, and whether they may prove to have been an isolated and temporary symptom of a difficult transition period in industrial decarbonization, or will proliferate and remain key policy elements far into the future. Still, the challenges they pose to established forms of international economic and environmental cooperation are not trivial, as are the risks arising from uncoordinated and unilateral initiatives.

While domestic interests and other overriding priorities may mute the appeal of such cooperation in the near term, the many benefits – political, economic and environmental – of cooperation as well as its ability to foster the perceived legitimacy and thus sustain international acceptance of BCAs will, over time, elicit growing pressure to engage in some form of international engagement. Much will also depend on the broader context of BCA cooperation, and whether, for instance, it is accompanied by efforts to honestly engage on the costs of implementation and the risks of protectionism, or includes mechanisms to extend support for developing countries that face difficulties complying with the attendant obligations.

Michael Mehling, Harro van Asselt, Susanne Droege, Kasturi Das, and Catherine Hall (2024), "Bridging the Divide: Assessing the Viability of International Cooperation on Border Carbon Adjustments", CEEPR WP-2024-06, MIT, April 2024.

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Michael Mehling, Harro van Asselt, Susanne Droege, Kasturi Das, and Catherine Hall, April 2024

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Event speakers Stwart Peña Feliz, MBA '23, Catherine Wolfram, PhD '96, Christopher Knittel, and Kathryn Hawkes during Q&A at an event on April 10, 2024 highlighting MIT Sloan's contributions to the climate space.

Photo Credit: Tim Correira

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