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Editorial.

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Energy has always had strategic importance, but developments over the last year have once more elevated the role of geopolitical and security concerns related to energy. What is perhaps new, however, is the degree to which these considerations are also spilling over into the energy transition, and influencing the choice of policies to advance energy system decarbonization. As the United States revisits long-held views on foreign policy and outlines the contours of a new international economic agenda, it has also found new appeal in industrial policy as a way of simultaneously advancing environmental, social and economic priorities. Different elements of this strategy – including the Inflation Reduction Act – are meant to foster economic prosperity and promote technological innovation, diversify supply chains, strengthen labor standards, and advance climate policy objectives. It may also be showing initial results: early indicators suggest a noticeable surge in spending on new manufacturing capacities for low-carbon technologies in the United States, for instance, spurred by the generous investment and production tax credits available under the IRA for eligible activities.

No agenda of this scope can avoid inciting difficult questions, however. Some difficulties are highly visible, such as the transatlantic tensions that erupted earlier this year over local content requirements and other conditions attached to IRA support. While Europe and the U.S. appear to be progressing towards a diplomatic resolution, striking differences remain in their respective approaches to decarbonization and threaten to erupt again in other areas of cooperation, including an initiative to address competitive and environmental impacts of imported steel and aluminum, that both sides are currently negotiating. Other questions are more fundamental: can a single strategy credibly pursue so many policy objectives at the same time, especially when some of these objectives may not in every case be reconcilable? What are the effects, for instance, of localization requirements on the cost and pace of the energy transition? Brandishing industrial policy to further environmental objectives is not new; but it has rarely if ever been attempted at this scale, and its long-term impacts on markets, fiscal budgets, and international relations have yet to be seen.

Even where the necessary materials and components for energy system decarbonization are abundantly available, other constraints will still need to be overcome. Increasingly, siting and permitting of energy infrastructure are proving the greatest barrier to the energy transition, ahead of technology availability and cost. Labor shortages and thorny, but essential, questions about the equity impacts of different energy choices likewise defy easy solutions. All this reminds us of the multifaceted nature of energy and environmental policy, and the importance of pursuing both deep and broad approaches to relevant research. Deep, in order to advance the state of the art of our understanding of a specific issue area or research question; and broad, to retain a systemwide perspective and identify the many ways in which changes in one area can affect other areas. As the articles in this newsletter once again highlight, MIT CEEPR has always benefited from both types of research by its faculty affiliates, staff, and studies, reflecting a wide variety of approaches and methodologies. That may also be the only way to do justice to the complexities of the energy system, not least as it embarks on a process of historical transformation.

Michael Mehling

Contents.

Research.

Natural Gas in the U.S. Southeast Power Sector under Deep Decarbonization: Modeling Technology and Policy Sensitivities

By: Aaron Schwartz, Jack Morris, and Dharik Mallapragada

An increasing number of public and private actors have announced "net-zero" emissions targets by mid-century. In the electricity sector, the United States' second largest source of carbon emissions as of 2020, achieving net-zero goals will require transitioning from today's fossil-dominated resource mix to one with substantially fewer emissions while providing reliable power for an increasing number of electrified end-uses, such as electric vehicles and heat pumps. Although the transition from coal to natural gas has driven 65% of the decline of U.S. power sector emissions from 2005 to 2019, it is unclear what role natural gas generation may play in the future generation mix, when achieving power-sector net-zero goals require rapid and sustained declines in emissions.

This study focuses on the American Southeast (which, for the purposes of this study, includes Tennessee, Mississippi, North Carolina, South Carolina, Alabama, Georgia, and Florida) which is responsible for about 20% of the nation's electric power sector emissions and hosts several utilities which have announced plans to operate at net-zero by mid-century. Unlike much of the United States, the Southeast is dominated by vertically-integrated utilities, which perform centralized grid planning and make their own decisions about which generation resources they aim to procure through integrated grid planning processes. We use a capacity expansion model that mimics this central planner perspective, along with perfect foresight, to estimate least-cost resource portfolios over five-year increments spanning 2020 through 2045 across several technology cost, emissions, and policy scenarios. To reflect the increase in load anticipated to accompany increased electrification of end-uses over the coming decades, load forecasts across all scenarios are derived from the "High" electrification scenario from NREL's Electrification Futures Study. Under this scenario, the system's peak load increased from 151 to 263 GW in 2020 to 2045.

All scenarios included some deployment of new natural gas, with totals across all planning periods ranging from 43 GW when using a low-end cost forecast for variable renewable energy and storage resources, to 81 GW when we assume that all existing nuclear plants (33 GW in 2020) in the region fail to receive second-lifetime extensions and retire at the end of their current license. However, this is dwarfed by the deployment of new VRE capacity; across scenarios, combined new wind and solar capacity range from 345–489 GW, and new storage capacity ranges from 72–118 GW. The deployment of natural gas with CCS (with 90% flue gas CO_2 capture) is sensitive to the emissions reduction pathway being modeled; natural gas with CCS doesn't appear in any scenarios under the least restrictive emissions constraints, but appears in all but one scenario featuring the most restrictive. The exception—a scenario where upstream methane emissions are counted towards the emissions budget—suggests that the scope of emissions encompassed by net-zero goals may have meaningful implications for the types of technologies needed to meet those goals.

A surprising result of our analysis was that increasing the stringency of the emissions limits did not necessarily result in a decrease in total, cumulative emissions over the planning horizon. In four of the six scenarios considered in our analysis (rows in Table 1), systems costs and cumulative CO_2 emissions are lower for the least restrictive ("High") emissions policy compared to the most restrictive ("Low") policy. This is attributed to greater utilization of existing coal generation in early model periods under the Low emissions policy, since it is uneconomic to replace existing coal with new gas capacity that would see little future use given the tight emissions budget. This result suggests that a balanced view of near-term and long-term emissions reduction would be prudent in regions with significant existing coal generation.

Finally, all else remaining equal, we find that policies discouraging new natural gas deployment, such as accelerated depreciation timelines and disallowing new gas without CCS after 2025, generally lead to greater cumulative emissions reduction compared to the corresponding scenarios without these policies, along with a marginal increase in systems costs (see the bottom two rows in Table 1). Such policies make it attractive to support early build out of natural gas generation to displace coal generation in the near term, while at the same time limiting cumulative new natural gas deployment in a way that minimizes asset stranding in future years with increasingly stringent emissions constraints. At the same time, it should also be noted that natural gas resources will likely operate differently in a low-carbon power system. We observe steep declines in natural gas capacity factors over time across scenarios, indicating a changing role for natural gas plant operation focused primarily on system reliability.

Aaron Schwartz, Jack Morris, and Dharik Mallapragada (2022), "Natural Gas in the U.S. Southeast Power Sector under Deep Decarbonization: Modeling Technology and Policy Sensitivities", CEEPR WP-2022-018, MIT, November 2022.

Sensitivity	Cost (%)			Emissions (%)		
CO_2 Policy	High	Med	Low	High	Med	Low
Reference	2.2	5.0	6.0	-31.8	-23.5	-26.9
Low Cost VRE and Storage	-2.9	-1.6	-0.4	-27.0	-24.5	-25.5
No Nuclear SLTEs	5.6	7.1	9.1	-32.6	-27.7	-33.0
Upstream Emissions	4.7	5.5	7.8	-34.1	-44.1	-40.2
Accelerated Depreciation	4.9	5.0	7.5	-27.9	-31.0	-31.2
Only CCS NG After 2025	5.3	5.6	7.2	-33.2	-29.3	-31.6

Table 1. Changes in net present cost and cumulative emissions with respect to a reference case without any emissions limits.

Siddhi S. Doshi and Gilbert E. Metcalf (2023), "How Much Are Electric Vehicles Driven? Depends on the EV", CEEPR WP-2023-01, MIT, January 2023.

Research.

How Much Are Electric Vehicles Driven? Depends on the EV

By: Siddhi S. Doshi and Gilbert E. Metcalf

Transportation is the single largest source of greenhouse gas emissions in the United States. A key element of federal climate policy is to shift personal transportation away from gasoline and diesel-fueled vehicles towards electric vehicles (EVs).

Swapping out gasoline and diesel vehicles with electric vehicles has raised a number of important policy questions including, for example, how the federal government raises revenue for the Highway Trust Fund. Currently, all revenue from the federal motor vehicle fuel excise tax is earmarked for this fund. As more EVs are purchased, fuel excise tax revenue will fall. This has led to renewed interest in enacting a vehicle-miles-traveled (VMT) tax to replace lost motor vehicle fuel excise tax revenue.

Recent studies on the distributional implications of a VMT-Gas Tax swap assume that households shifting from gasoline or diesel-powered vehicles to EVs do not change their driving behavior. A recent paper by Davis (2019) challenges this assumption. Davis argues that "electric vehicles are driven considerably less on average than gasoline and diesel-powered vehicles." Davis correctly notes that "the less electric vehicles are driven, the smaller the environmental benefits from electric vehicle adoption."

In addition to smaller environmental benefits, estimates of driving and market penetration of EVs in the future would influence EV-related policy decisions and analyses, with potentially important distributional implications. If higher income households are more likely to own EVs, and if they drive fewer miles upon switching from a gasoline or diesel-powered vehicle, then the burden of a revenue-neutral VMT-gas tax swap will fall more heavily on lower-income households.

While Davis makes an important point about the relevant counterfactual for EV driving behavior, we think the evidence contained in Davis' data source—the 2017 National Household Travel Survey (NHTS)—is a bit

Type of Electric Vehicle	(1) Self-Reported VMT	(2) Average VMT	(3) Adj. Average VMT	(4) NHTS Reported VMT
Plug-in Hybrid	-1,226***	-1,956***	-3,046***	-669*
Long Range All-Electric	37	-1,010	-78	1,802**
Hybrids	2,542***	1,151***	2,169***	1,282***
Short Range All-Electric	-3,296***	-2,125***	-4,442***	-5,123***
R^2	0.11	0.17	0.11	0.09
Number of Observations	62,873	69,790	69,778	79,626

Note: This table reports the difference in driving between the vehicles identified in the first column and gasoline or diesel operated vehicles. Each column reports a different measure of annual vehicle miles traveled. All estimates are calculated using sampling weights. The second row now captures only long-range EVs (Teslas). There are 436 EVs in the dataset, of which 113 are long-range, 247 are short-range and the range for 76 EVs is unknown or misclassified. We drop these 76 EVs for this regression.
The *p*-values are indicated by stars: *** p<0.01, ** p<0.05, * p<0.10

Table 1. Electric Vehicle Driving Relative to Gasoline and Diesel-Powered Vehicles: Household and Vehicle Controls (Control for Short-Range EVs)

more nuanced than it first appears. Our analysis of the same data suggests that EV driving range is a key factor in explaining differences in annual mileage for EVs versus gasoline or diesel-powered vehicles: if one focuses on long-range EVs, we find that the driving differences go away.

When not controlling for owner or vehicle characteristics, our initial results concur with Davis. We find that EVs are driven between 2,500 and 4,200 fewer miles annually on average than gasoline or diesel-powered vehicles. Plug-in hybrid vehicles are driven on average anywhere between 800 and 2,900 fewer miles than gasoline or diesel-powered vehicles. Conventional hybrids, on the other hand, are driven more than gasoline or diesel-powered vehicles by anywhere from 690 to 2,100 miles on average, depending on the measure of annual driving.

What explains the difference in driving between EVs and gasoline or diesel vehicles? One hypothesis is selection. Environmentally conscious drivers may simply drive less and prefer EVs. Drivers in urban areas, where people drive less, may prefer EVs. EVs may be secondary vehicles for some. While we cannot fully test for all these preferences, we use the available set of household-level and driver-specific information to test the selection hypothesis. We find that after controlling for selection variables, the estimated differences in driving between EVs and gasoline or diesel-powered vehicles becomes less negative.

However, sample selection does not fully explain the differences. Even after controlling for household, vehicle, and regional characteristics, EVs are typically driven less than gasoline and diesel-powered vehicles. Another possible explanation of the lower annual VMT is battery range for EVs. Davis notes this but does not test this hypothesis. In our analysis shown in Table 1, we add an indicator variable for whether an EV has battery range of 100 miles or less. Not surprisingly, in all cases, EVs with short battery range are driven anywhere from 2,000 to 5,000 miles less than EVs with a high battery range. However, when comparing EVs to gasoline or diesel-powered vehicles, we find that long-range EVs are not necessarily driven less than internal combustion engine vehicles.

However, we must note that Teslas are the only long-range EVs in our data, so it is difficult to distinguish a Tesla effect separately from the range effect. Our controls for household characteristics, such as household income and location will capture some of the Tesla effect. Additionally, assuming that Teslas are preferred by environmentally conscious individuals that drive less, the Tesla effect would bias our result downward. This dataset may also capture many early adopters of Teslas, who are also likely to be drivers who drive less. Given all this, it is even more meaningful that despite a potential Tesla effect biasing our result downward, long-range EVs are not necessarily driven less than gasoline or diesel vehicles.

Once one accounts for battery range, the sharp difference in annual miles driven between EVs and gasoline and diesel-powered vehicles goes away for long-range EVs. With battery range increasing dramatically (see Figure below), focusing on longer-range EVs seems relevant for any research looking at the efficiency or distributional implications of policy to incentivize greater take-up of EVs. The distributional considerations are especially important for thinking about tax proposals for a VMT tax to replace in part or entirely the current motor vehicle fuel excise tax. Assuming that EVs are driven fewer miles than the vehicles they replace would bias such a revenue-neutral tax reform towards being more regressive, assuming EVs are disproportionately purchased by higher income households.

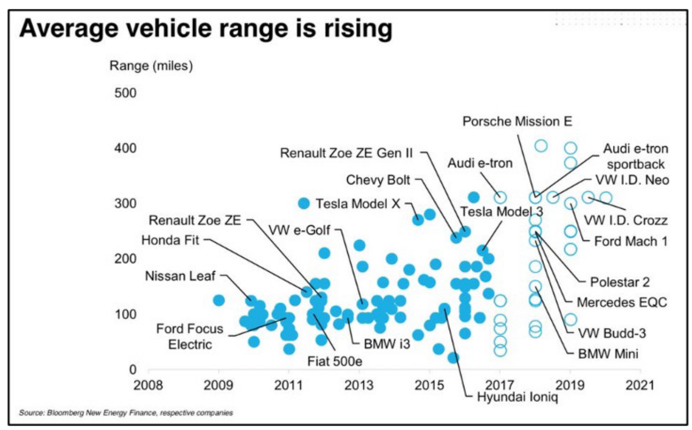

Figure 1. Electric Vehicle Range Over Time

It is also important to remember that the 2017 NHTS dataset is based on sampling conducted in 2016, 6 years before this paper was written. The EV environment has experienced massive improvements in terms of technology, infrastructure, and adoption since then. If we see disappearing VMT differences using data from 6 years ago, we should expect to see much better outcomes today and moving forward. In the end, a definitive answer to the question of whether EVs are driven differently than gasoline and diesel-powered vehicles may have to wait for the next release of the travel survey.

Research.

Accelerating Electric Vehicle Charging Investments: A Real Options Approach to Policy Design

By: Emil Dimanchev, Stein-Erik Fleten, Don MacKenzie, and Magnus Korpås

Significant public resources are being dedicated to stimulating private sector investment in electric vehicle (EV) charging infrastructure. In the U.S., firms can access grants made available by the recently passed Infrastructure Investment and Jobs Act and the Inflation Reduction Act. The question this research addressed is how state and local governments can make the most of such public funding to accelerate investment in fast charging stations for EVs.

A key goal for governments is incentivizing fast charging stations in currently underserved rural areas. Such investments present challenging economics for private sector investors due to high upfront costs in combination with low and uncertain demand. For firms that can choose when to invest, investment carries an opportunity cost, which incentivizes delaying development until demand is sufficiently high.

To effectively accelerate investment, subsidy design should account for the full set of incentives facing investors. For this purpose, we develop a real options model of investing in a representative fast charging station in the U.S. Our model captures optionality in investment timing, thus allowing us to quantify optimal investment timing, which previous analyses omitted due to a reliance on simpler Net Present Value (NPV) methods.

We model the investment in a single fast charging station comprising six 350 kW charging points. Demand for charging is assumed to be low in the first year, and for this we use a typical low utilization rate of 5%. Future demand growth is uncertain, which we represent as a binomial scenario tree with an average annual demand growth of 9% and volatility based on historical charging data. We assume the investor considers a decision-making horizon between now and ten years in the future and must choose the point in time within this horizon at which to invest. Our model computes the optimal investment decisions for each possible demand level and at each possible point in time using a standard backward recursion algorithm. We then estimate the optimal timing of investment by simulating many possible future scenarios using a Monte Carlo algorithm.

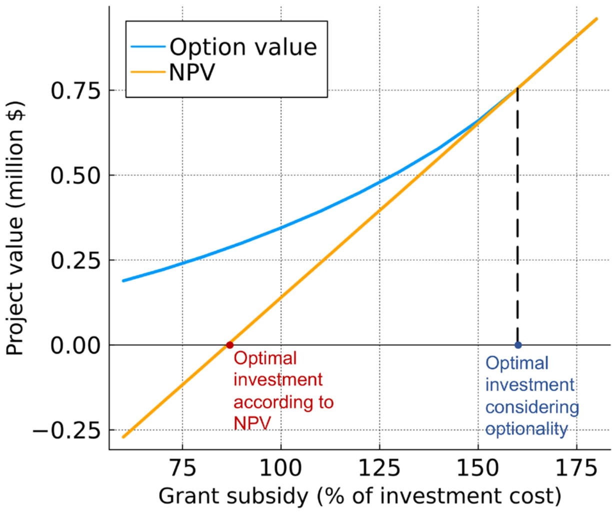

Figure 1. Value of investment in a fast charging station relative to the size of a grant subsidy

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Our analysis shows that optionality in investment timing has substantial impact on the effectiveness of government subsidies and important implications for subsidy design. We first demonstrate that subsidies informed by traditional NPV methods either underestimate the amount of subsidy required to trigger investment or overestimate the effectiveness of the subsidy. An NPV analysis would recommend a subsidy large enough for the project to break even so that its discounted future revenues equal its costs. For the case we consider, this would result in a grant equal to 86% of the investment cost (shown by the red dot in the figure above). This large magnitude is largely driven by the combination of high investment costs, low demand, and substantial demand charge costs (as well as our choice to omit any revenue sources other than the re-sale of electricity). However, such a grant would not cover the opportunity cost of investment (shown by the blue line). For the project to justify this additional cost, our model estimates that a grant equal to 160% of the project's investment cost becomes necessary (shown by the blue dot in the figure), or roughly twice as much as the subsidy recommended by NPV. On the other hand, if the investor only received the NPV-informed grant, our model suggests that it would be optimal for the investor to wait more than 5 years before investing.

This research suggests several policy design changes that can improve the effectiveness of charging subsidies in the presence of optionality. A recently proposed option is for governments to provide long-term contracts that provide investors with guaranteed revenue streams, a version of which has been implemented in the Netherlands. A specific policy we test is a two-sided contract for differences, which compensates firms for any revenue shortfalls below a pre-determined "strike" level and requires firms to pay back any revenues in excess of this level. We find that, by directly addressing optionality, such contracts can effectively accelerate investment. We further estimate that such contracts are substantially more cost-effective than grants, requiring less financial support to trigger investment.

A simple policy alternative is the introduction of a phase-out schedule for subsidy grants. This would provide a considerable improvement in cost-effectiveness (compared to the standard grant) by decreasing the value of delaying investment. We test alternative phase-out timelines and find that a 10-year phase-out schedule may be a pragmatic way to cost-effectively accelerate charging investments.

Surprisingly, this paper shows that reducing (but not eliminating) investment risk has relatively little impact on investment timing. To explore this, we test a policy such as a Zero Emission Vehicle standard that mitigates EV adoption risk by effectively mandating a given level of EV penetration. In this case, firms continue to face some risk (e.g. related to driving behavior), and our real options model suggests that the optimal investment decision is changed only slightly. This suggests that effective de-risking would require that governments address residual risks additional to the uncertainty in EV adoption. In practice, ZEV mandates can still play an important role in charging infrastructure policy. Our analysis only represented ZEV standards as a reduction in the uncertainty in future EV adoption. But if such policies increase EV adoption, they would by extension have a positive effect on charging investments.

The relevance of our analysis is limited to cases where firms have the option to delay investing. This is particularly likely to be the case in low-demand rural regions. Therefore, analyses informed by real options can help public agencies understand and stimulate investment decisions in areas that may otherwise be underserved, reducing inequalities in vehicle electrification and more effectively alleviating range anxiety concerns.

Emil Dimanchev, Stein-Erik Fleten, Don MacKenzie, and Magnus Korpås (2023), "Accelerating Electric Vehicle Charging Investments: A Real Options Approach to Policy Design", CEEPR WP-2023-03, MIT, February 2023.




Gilbert E. Metcalf and James H. Stock (2023), "The Macroeconomic Impact of Europe's Carbon Taxes", CEEPR WP-2023-02, MIT, January 2023.

Research.

The Macroeconomic Impact of Europe's Carbon Taxes

By: Gilbert E. Metcalf and James H. Stock

Economists widely agree that putting a price on carbon emissions is a key element of economically efficient policies to reduce greenhouse gas emissions. The two most straightforward ways to apply a price are a carbon tax and a cap-and-trade system. A carbon tax can be levied on fossil fuels and other sources of greenhouse gas emissions based on their emissions. A cap-and-trade system limits emissions to a set overall amount (the cap) and allows polluters to trade the rights to those scarce emission rights. In recent years, members of Congress have filed numerous bills to establish national carbon tax systems and a few cap-and-trade bills. This reflects the growing consensus that action is needed at the national level to curb our carbon pollution and that a carbon tax is the most straightforward way to do so.

However, despite this consensus, resistance to carbon taxation policies is significant, in part due to concerns about the economic impact on jobs and growth.

In our paper, we assess the economic costs of a carbon tax, particularly relating to GDP growth and employment. With three decades of data since the first carbon taxes were implemented, we now have enough experience with carbon tax systems around the world to carry out statistical analyses of existing systems.

We carry out an analysis of the 31 European countries that are part of the EU-wide emissions trading system (EU-ETS). All of these countries price a portion of their emissions through a cap-and-trade system. However, fifteen of these countries also impose a carbon tax, mostly on emissions not covered by the EU-ETS. By leveraging the variation in carbon tax systems within EU-ETS countries, we can identify the incremental impact of carbon taxes on emissions, output, and employment.

We find the following: For a wide range of specifications, we find no evidence of adverse effects on GDP growth or total employment (see Figure 1). Our results are robust. We control for how carbon tax revenue is used, and whether we limit the analysis to countries with large tax rates or to the Scandinavian countries that were early adopters of carbon taxes as part of a Green Tax Reform, allowing for marginal effects to depend on the level of the tax, the covered share, or other cuts of the data.

We also test and cannot reject the hypothesis that the carbon tax has no long run effect on growth rates of GDP, emissions, and employment. In other words, we find that the tax potentially shifts the long-run path of the log levels of those variables, but those paths are parallel to the no-tax path. This parallel shift finding is consistent with macroeconomic theory that suggests growth rates are driven by fundamentals, such as aggregate technological progress, which are unaffected by changes in relative prices. It is also consistent with most general equilibrium modeling of climate policy.

We find cumulative emission reductions on the order of 4–6% for a tax of $40 per ton of CO_2 covering 30% of emissions (see Figure 2). We argue that this is likely to be a lower bound on reductions for a broad-based carbon tax in the U.S. since European carbon taxes do not include sectors with the lowest marginal costs of carbon pollution abatement (electric generation, energy intensive manufacturing). We show that these estimated emissions reductions are in line with estimated price elasticities of demand in the transportation sector.

Our approach differs from the existing (scant) empirical literature on the macroeconomic impact of carbon taxes by focusing on macroeconomic time-series econometric methods instead of the more typical event study methods used in microeconomic assessments. This macroeconomic approach is designed to respond to policymakers' concerns that a carbon tax could hurt the economy. Unlike microeconomic analyses focused on individual sectors, our analysis accounts for the fact that the tax's adverse impacts in one sector can be offset by positive impacts on other sectors. While distributional impacts are certainly relevant, focusing only on the impacts on sectors directly bearing the tax can overstate the adverse macroeconomic impacts of carbon pricing.

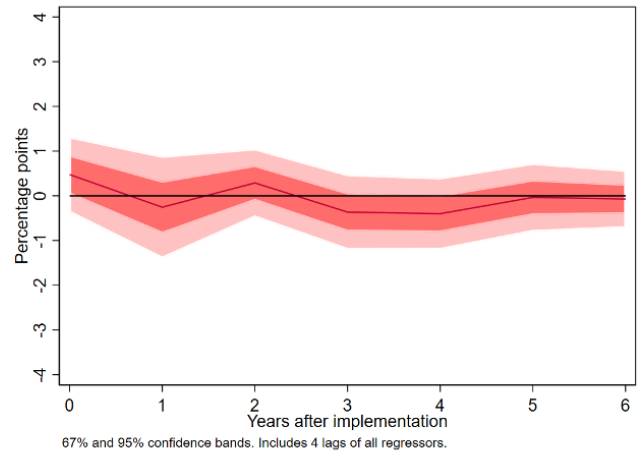

Figure 1. Effect on GDP growth of a $40 carbon tax covering 30% of emissions: LP Regression – Restricted

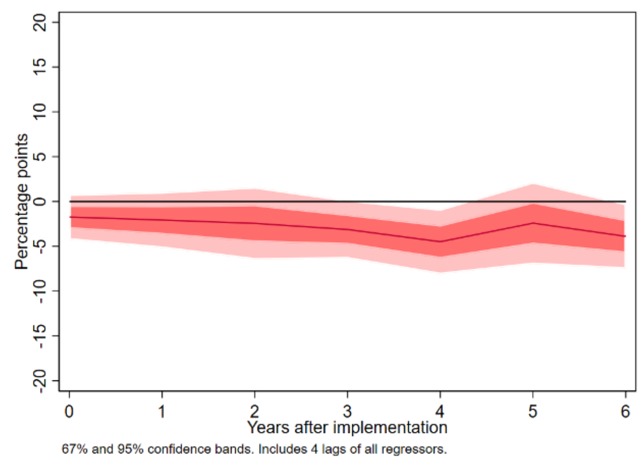

Figure 2. Effect on level of emissions in covered sectors: LP Regression – Restricted

Research.

Power Price Crisis in the EU 3.0: Proposals to Complete Long-Term Markets

By: Tim Schittekatte and Carlos Batlle

Since the end of the summer 2021, Europe's energy prices have reached sustained, unprecedented, and unexpectedly high levels, raising a vivid debate across the European Union (EU). The current energy crisis is first and foremost a natural gas crisis. However, electricity prices have also attained sustained high levels.

There are reasons to think that these high prices will not be an exceptional situation. There is an increasingly widespread perception that long-term marginal generation costs, signaled now by renewable technologies, are, and very likely will be for quite some time, well below the short-term marginal prices often set by gas-fired generators.

As a result, since the onset of the crisis, governments have spent billions of euros, often representing several percentage points of their national GDP, to shield consumers and industry from high prices. Amid these efforts, the European Commission started working on its own assessment of the existing power market design. On the 23rd of January 2023, the Commission launched a public consultation on the reform of the EU's electricity market design. A proposal for a market reform has recently been presented.

We provide our perspective on the EU's current electricity market design. The two key issues we consider are (1) investment risk management and (2) a lack of adequate hedging of end users against periods of sustained high prices. We do not believe these two features can be addressed with one tool. These two different objectives engage different groups of stakeholders—newly connecting generating units and existing generators—with very different risk profiles. Therefore, these challenges require different regulatory solutions.

In terms of investment risk management, at this stage, we deem the emphasis should be on finding the most adequate contract format that balances investment support and short-term economic dispatch with medium- to long-term planning efficiency. We advocate for a contract format that resembles a standard contract-for-differences (CfD) but keeps dispatch incentives intact without significantly increasing investment risk. More precisely, we recommend a capacity-based support mechanism complemented with ex-post compensations or penalties resulting from the plant's performance compared to a reference plant.

Tim Schittekatte and Carlos Batlle (2023), "Power Price Crisis in the EU 3.0: Proposals to Complete Long-Term Markets", CEEPR WP-2023-04, MIT, February 2023.

To address the second major market flaw, the lack of adequate hedging of end users against periods of sustained high prices, we propose two mechanisms: (1) a market maker obligation (MMO) on incumbent vertically integrated firms and (2) the purchase (via centralized auctions, if sufficient competition can be guaranteed) of affordability options. Affordability options (AOs) are a non-distortive instrument that can be used to limit future unaffordable expenses and excessive revenues.

Our two objectives engage different groups of stakeholders - newly connecting generating units and existing generators. To engage newly connecting generators, the objective should be to speed up RES penetration at the lowest system cost. This implies removing unnecessary administrative and technical barriers for connection, optimizing the risk management, and maximizing competition. To do so, we do not recommend giving away the right to connect to the transmission network on a first-come-first serve basis anymore. The ability to auction the right to connect, in the current context, does not only allow for the benefits of competition to be leveraged for access to the system, but also makes a more efficient coordination of the generation and transmission capacity expansion possible, which is a major challenge nowadays.

Beyond the consideration of financial hardship of consumers, this scenario of high electricity prices unveils a higher-order threat: the potential loss of trust (and patience) of the political class and the mass media in the whole market compound. A policy shock of this nature, potentially leading to future loss of efficiency in the decarbonization process, can no longer been seen as a risk. It is a fact. Therefore, we argue that proactively protecting certain subsets of consumers against affordability risks could be justified. This does not necessarily imply subsidizing these end users, what we mean is the possibility to act on their behalf.

We believe the best path forward would be to engage end users in need in some financial long-term hedge. When the crisis calms down, we propose the organization of centralized regulatory-driven auctions for AOs, which can be complementary to a market maker obligation. It is important to maximize competitive pressure in these auctions. To do so, besides considering a reserve (maximum) price, we recommend minimizing the volume of AOs to those in true need. The decision about the volume of AOs shall be based on (1) which end users are deemed to (or want to) be protected from sustained high prices, and (2) the total volume of production already under existing CfDs.

The main aim of our paper is to contribute to the ongoing power market design discussion in the EU. A lot more work is required to further work out the complications and different possible solutions that we sketch. We hope our contribution can be seen as productive by focusing on the way forward and outlining the potential steps we believe are needed to improve the EU's current power market design.

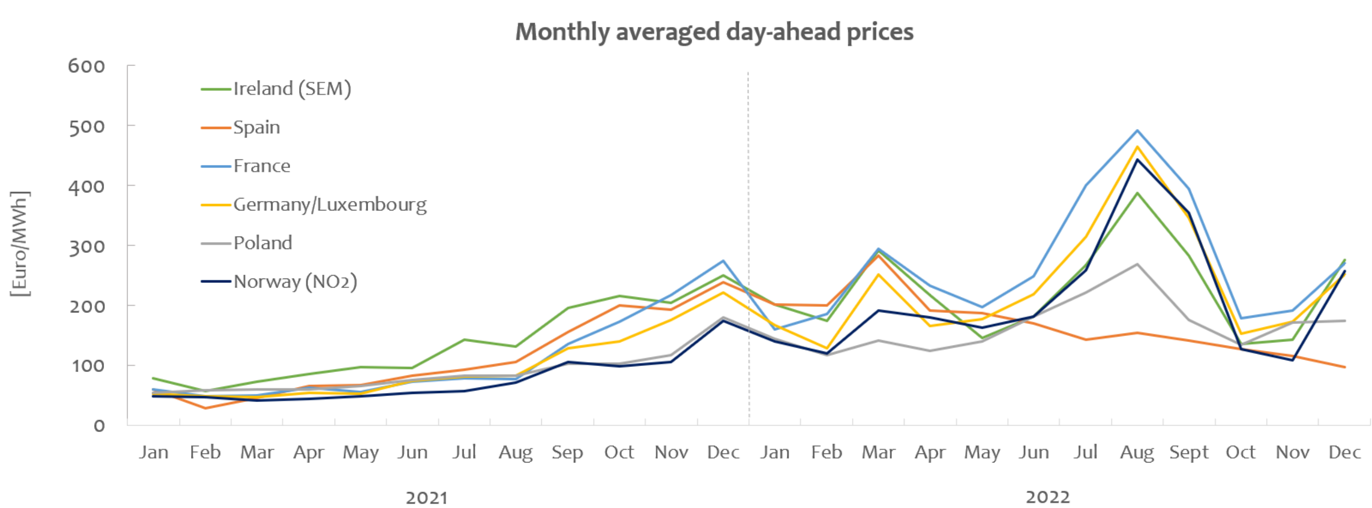

Figure 1. Monthly averaged day-ahead prices for six bidding zones 2021–2022. Based on ENTSO-E (2022).

Matti Liski and Iivo Vehviläinen (2023), "Redistribution Through Technology: Equilibrium Impacts of Mandated Efficiency in Three Electricity Markets", CEEPR WP-2023-10, MIT, April 2023.

Research.

Redistribution Through Technology: Equilibrium Impacts of Mandated Efficiency in Three Electricity Markets

By: Matti Liski and Iivo Vehviläinen

New technologies offer captivating opportunities to trade and improve efficiency in markets, illustrations ranging from ICT to smart technologies for electricity consumption. Aware of this, policy makers have sought to harness these opportunities in electricity markets by mandating the adoption of smart consumer technologies and new producer technologies such as large-scale storage. The mandates have broad equilibrium impacts when market adoption of technologies is not otherwise taking place. On account of equilibrium impacts, do consumers end up benefitting from the mandated allocative efficiency?

First, the mandates impact equilibrium price dispersion and thereby one source of surplus to consumers. Intuitively, a consumer benefits from the option to optimize, e.g., to charge an electric vehicle at occasional bargain prices rather than at a flat mean-equivalent price. The importance of this option can be captured by a pass-through rate measuring the incidence of allocative inefficiency between consumers and producers. Second, if supplies are positively correlated with demands, consumers can get frequent bargain prices even when they do not respond to prices at all. The mandated efficiency makes such bargains smaller. Third, the mandates change the overall price level that consumers face. We develop a novel measure predicting the price-level change: it measures the convexity of market excess demand, linking the consumer surplus gains to the market rudiments, the shapes of demand and supply.

We then develop empirical counterparts of the pass-through rate, correlation, and convexity of excess demand by using micro-data on over 160 million bids from three distinct markets trading identical goods: the electricity wholesale markets in California, Nordic countries, and Spain. This enables us to conduct the same efficiency-improving "mandate" in each market to quantify the three determinants of surplus variations. In the experiment, we use the actual bids for market clearing after adding 1 gigawatt (GW) of capacity for improving the efficiency of allocations, hour by hour. Whether it is a retailer controlling customers' consumption by taking advantage of smart meters and remote controls, a producer exploiting grid-based storage solutions, or an individual optimizing the charging of EV, the idea is to buy market electricity when prices are low and sell (or, not use) it when prices are high.

A consistent result arises from all three markets: the private trading surplus may be lost with a reduced price dispersion but the consumer benefit from a lower price level is overwhelming. This price-level effect is captured by the empirical convexity measure of excess demand. It explains close to 90% of the surplus variation in California, 80% in the Nordics, and 40% in Spain. Price level changes have a flip-side implication: incumbent firms end up losing surplus in all markets; the surplus redistribution is substantially larger than the social value of the technologies, which is low in all markets.

Excess demand, the difference between demand and supply, inherits its convexity properties mainly from supply if demand is relatively inelastic. Consumers tend to benefit (lose) from an efficiency mandate when the supply is convex (concave) in quantities. Intuitively, a steeply rising supply reservation price of a convex supply reflects a shortage, an "under-supply" situation in which a technology such as large-scale storage helps lower the average price. In contrast, the same technology increases the average price when the supply is concave, an "over-supply" situation in which a large supply (e.g., gas-fired power) becomes available when the price exceeds a certain reservation level.

We estimate that when the mandate changes the daily price expectation by one euro/dollar, the daily consumer surplus changes by .226 million in California, 1.06 million in the Nordics, and .147 million in Spain. The mandate can change the price expectation in either direction, depending on the variation of under- and over-supply situations, and therefore the final impact of the mandate on consumer surpluses accumulates as a function of this variation in days over a year. For 2015–2020, we evaluate that the mandate of controlled size 1GW would have benefitted consumers in all markets. In the Nordics, the surplus gain to consumers from a mandate of size 1GW is ten times larger than the total (gross) social surplus!

In California, hourly price differences within a day start to increase in the spring, with depressed day prices and peaking evening prices. Solar PV systems crowd out a mix of gas-fired generation when the sun rises but the gas-fired units must quickly ramp up when the sun sets. In these situations, the supply is typically convex in prices (i.e., concave in quantities), and the demand is relatively inelastic (see Video, Panel A). Then, the excess demand is concave, and efficiency improvement works against the consumer surplus, as it increases the daily price level. Consumers lose day-by-day, until the trend is reversed later in the summer. A higher demand for cooling pushes the power system closer to full capacity, and the concave part of the supply curve applies (i.e., convex in quantities, see Video, Panel B). The efficiency improvement reduces the peak power generation and this lowers the peak prices by more than what the prices rise during the off-peak periods. In the end, over the year, the consumer surplus remains positive.

In the Nordics, the daily price dispersion is small for a large part of the year, as the hydro resource provides flexibility for counterbalancing the wind power intermittency and demand variation. Nearly all of the consumer surplus gain for 2016 comes from a few winter days when a cold spell leads to peaks in electric heating demand and prices. Demand is inelastic, and supply is concave in prices (i.e., convex in quantities, see Video, Panel C). 1GW additional capacity for reallocating loads reduces the impact of the market-level supply shortage in production and this brings consumer surplus gains that are significantly larger than for the other markets.

In Spain, the data suggest that the demand is more elastic than in the other markets, bringing stability to the surplus gain development over the course of the year: the demand elasticity reduces price peaks and also prevents prices from falling quickly in a positive supply shock. Intuitively, demand and supply come close to being linear (see Video, Panel D), suggesting that the mandate has a moderate impact on price levels—an alluring consistency with the theory prediction.

Our approach in novel in using multi-market granular micro-data on bids to simulate how the equilibria implied by the bids are affected by the mandates. The approach lets the data tell if the excess demand is concave or convex, which allows us to firmly link the empirical and theoretical results to explain the variation of surpluses in the data. The results add to the emerging literature that emphasizes nonlinearities in understanding data: nonlinearities of electricity supply seem to be of growing importance because high shares of renewables increase the variation of capacity utilization rates. We also contribute to the literature on how to activate consumers to use ever-better smart appliances by analyzing how a large-scale deployment of consumer-side technologies impacts the market equilibrium. The multi-market approach may prove useful when studying, for example, the impact of data centers and cryptocurrency mining on the "world electricity market".

Referenced Video Links.

Panel A Video: https://ceepr.link/2310A

Panel B Video: https://ceepr.link/2310B

Panel C Video: https://ceepr.link/2310C

Panel D Video: https://ceepr.link/2310D

Commentary.

Economy-Wide Decarbonization Requires Fixing Retail Electricity Rates

By: Tim Schittekatte, Dharik Mallapragada, Paul L. Joskow, and Richard Schmalensee

Reaching ambitious CO_2 emission-reduction targets will require substantially electrifying important energy-intensive sectors, while at the same time decarbonizing the electricity supply mix and thereby raising the cost of electricity. Recent economy-wide decarbonization studies, such as the IEA 'Net Zero by 2050 Scenario' (Figure 1) estimate that about 40% of 2020–2050 emission reductions will come from electrification, leading to more than a doubling of the share of electricity in final energy consumption by mid-century. Absent fundamental reform of retail electricity rates, this massive transformation will be substantially more difficult than necessary.

Historically, electric meters of residential and small commercial customers could only record total consumption between readings, which as a practical matter were infrequent (often monthly). Electricity was priced on an almost flat volumetric rate, i.e., a constant price per kWh of electric energy consumed, determining most of the bill, plus a small fixed charge ($/connection). Very roughly, the volumetric price was determined by dividing the total costs the utility had to cover in some period—including fuel for current generation and charges (such as interest on debt) related to past investment in generation, transmission and distribution—by expected kWh demand in that period. Regimes of this basic sort still dominate in the U.S., where only 7.3% of U.S. consumers are enrolled in alternative rate plans. A similar situation prevails in most of the rest of the world.

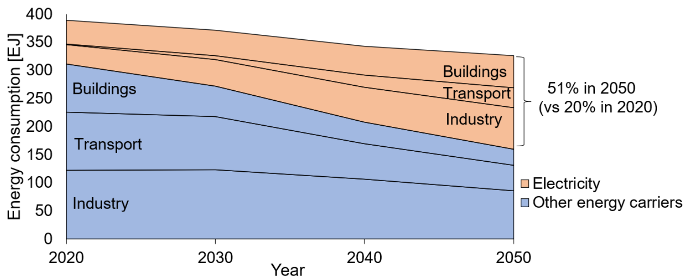

Figure 1. Evolution of the electrification per sector in the EIA's 2021 Net Zero Emissions by 2050 Scenario.

Exclusion of "Other sectors" (representing 5.5% of energy consumption in 2020) as no breakdown per energy carrier is provided.

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This sort of retail pricing will discourage efficient electrification in two related ways. First, retail customers generally do not see the often-substantial hour-to-hour variation in the marginal cost of electricity supply, which is reflected in spot wholesale prices. This means they have no incentive to reschedule demand to periods when the cost of electricity is lower than average. The inability to do this will make the total cost of utilizing electric technologies with load-shifting capability inefficiently high. This problem will grow as societies seek to increase the share of electric vehicles (EVs), perhaps the leading example of a technology with load-shifting capability, and HVAC systems based on heat pumps.

The increased penetration of advanced meters has recently made it possible to implement rate plans with time-varying prices by lowering the costs of recording consumption with high frequency (e.g. hourly) and with communications capabilities that would support load control options, so that this problem is, in principle, soluble economically. As of 2021, there were over 110 million advanced meters with these capabilities installed in residential (97 million) and commercial (13 million) locations in the U.S. Only a small fraction of these meters are presently being used to support more effective retail rates of the type we discuss here.

The second reason that traditional rate designs discourage electrification is the way that investment-related charges (as well as utility costs incurred to support social programs such as subsidies for energy efficiency programs) are reflected in electricity prices. In the short run, capital costs are, by definition, fixed and do not vary with instantaneous variations in consumption. Thus, volumetric electricity prices that include fixed costs are too high to provide good short-run price signals and inefficiently discourage electrification. For example, Borenstein and Bushnell estimate short-run marginal generation costs over 2014–2016 by utility-state in the U.S. and find that these costs average around only one-third of average volumetric rates.

This does not mean that consumers are paying too much for electricity, however. If the average volumetric rates at retail were reduced to around the average marginal cost of supplying power, utilities' revenues would fail to cover the significant fraction of their total cost that reflects historical investments in transmission and distribution capacity. Moreover, in the longer run, additional investments in network capacity will be required to serve growing electricity demand, and the incremental capital costs involved may well be higher than the historical costs reflected in today's retail rates. Electricity consumers need to cover network capacity costs, but in order to maintain incentives for electrification, this should not be done via inefficiently high volumetric rates. Rather, there is a need for substantially higher capacity charges, unrelated to current kWh consumption but linked to impacts on future network investment costs. We discuss below how charges for network investment costs of this sort might be set equitably while encouraging efficient behavior.

Here, we make the case for urgent action to reform retail electricity rates so that they that encourage, rather than work against, cost-efficient electrification while not ignoring considerations related to equity, complexity, consumer acceptability, and the recovery of reasonable costs incurred by utilities. We do not propose a single optimal solution for all situations, but rather we have identified particularly promising directions of reform. We now discuss in turn potential solutions to the two problems identified above.

Problem 1: Most volumetric rates do not mirror hourly variations in marginal cost.

Figure 2 provides data on wholesale prices in Texas (ERCOT) and California (CAISO), two systems with relatively high penetration of intermittent renewable generation. The top panels show hourly wholesale prices for 2012 to 2020, and the bottom panels show more detailed average wholesale price patterns by hour. The Figure shows that wholesale prices can vary substantially from one hour to another. We can see from the top panels that there are a few hours each year with very high prices, signaling system stress conditions during which demand reductions are extremely valuable. We can see from the bottom panels that within the day, there are fairly consistent price patterns indicating when it is relatively more or less costly to the system as a whole to use electricity.

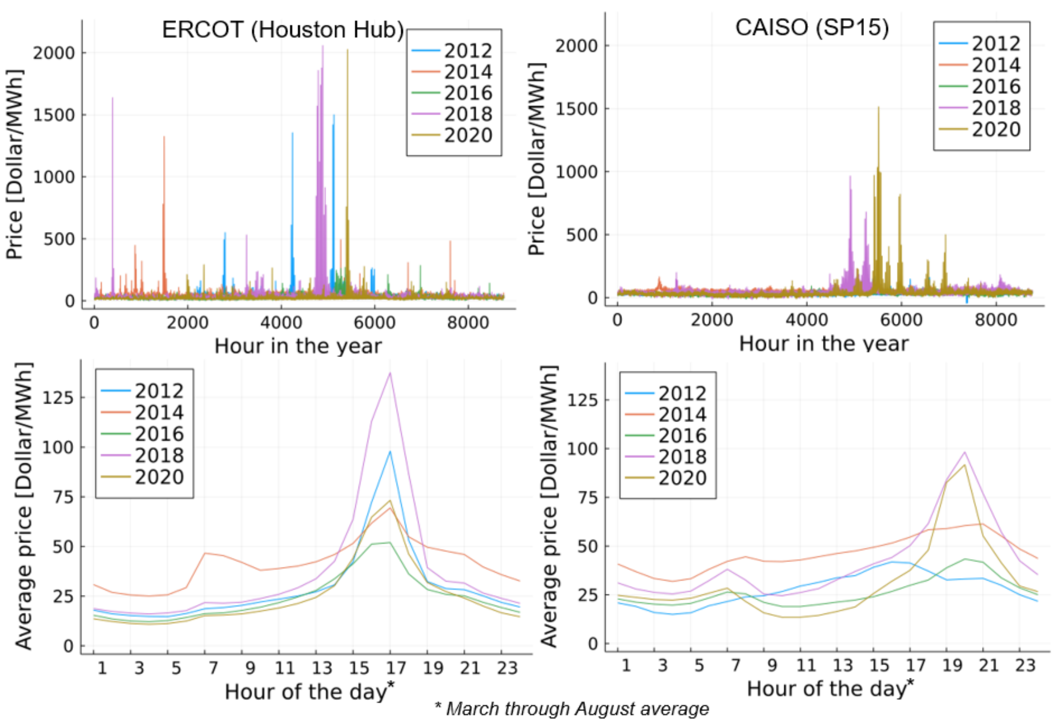


Figure 2. Top- Day-ahead price series for the Houston Hub in ERCOT (left) and SP15 in CAISO (right) for selected years, down-averaged daily day-ahead prices in CAISO from March through August for the same systems and years.

As power systems decarbonize, relying heavily on wind and solar generation that have zero marginal cost, wholesale spot prices are expected to become more volatile, with more hours of very high prices and many more hours of very low prices. The efficiency cost of time-invariant volumetric rates, which provide no incentives for shifting demand to periods when marginal cost is low, will accordingly increase — and increase substantially as the importance of demand from EV charging and other sources of shiftable demand increases. The Econ 101 reform would be to charge consumers wholesale spot prices, adjusted if necessary for transmission and distribution losses. While advanced meters have made such real-time pricing (RTP) widely feasible today, RTP is still not popular.

One reason for their unpopularity is that optimization takes consumer effort, and electricity typically only represents a small percentage of household spending in wealthy nations. Thus, the benefits from frequently reacting to price information might rarely be worth the effort involved. On the other hand, failure to pay attention can occasionally be very costly. The business model of Griddy, a Texas retailer, was based on RTP, leading, most of the time, to low bills even if consumers didn't react to price changes. In February 2021, however, wholesale spot prices in ERCOT were at their maximum for four straight days. When the crisis hit, Griddy urged its 29,000 customers to switch to alternative suppliers with fixed, lower rates, but only 9,000 did so. In May, the Texas legislature outlawed RTP. Not only will increased spot price volatility mean that the efficiency costs of time-invariant rates will grow, but after Griddy, RTP will be even less attractive than before because of higher perceived bill risk.

Popular "second-best" rate designs that embody some of the time-varying nature of spot prices are time of use (TOU) rates and critical peak pricing (CPP). TOU rates are predefined, e.g., at least a year ahead, and calibrated on historical price data. Typically, TOU rates differ by season, type of day (workdays or weekends), and/or time of the day (e.g., peak, shoulder, or off-peak). CPP provides extra incentives to reduce consumption during a handful of hours with the highest wholesale prices. An alternative to CPP is for consumers to agree for an ex-ante bill credit to allow for remote load control (that they can override at a cost) during CPP events, giving the load-serving entity the ability to cut customer utilization when system capacity is heavily stressed. These programs, when in place, are generally well-subscribed in U.S. jurisdictions. For example, many U.S. utilities offer air conditioning (AC) cycling options that give the utility to ability to cycle the customers' AC for a maximum number of days and hours per day during the summer when demand peaks on very hot days in most of the U.S.

Most of the existing academic literature has been skeptical about TOU rates, typically finding that they capture only about one-fifth of the efficiency gains that would be produced by RTP on an hourly basis with alert consumers. This literature mostly focused on demand characterized by independent hourly demand functions and thermal-dominated generation. In recent work, we introduce alternative assessment criteria that are tailored to a context with high volumes of intra-day shiftable loads. Using historical data from three U.S. markets, we find that while TOU rates are obviously not good at predicting scarcity events or absolute spot price levels, they are reasonably good at predicting within-day relative price differences. If TOU rates are adjusted relatively infrequently, consumers should be able to develop efficient usage habits, especially taking advantage of intra-day load shifting opportunities based on relative price differences.

Considering these recent results and the simplicity and low bill risk that makes TOU rate designs more attractive than RTP to risk averse consumers, we recommend the acceleration of the wider adoption of TOU rates, especially when accompanied by a CPP program built around load control options. While TOU rates are currently not widely adopted in the U.S., they are increasingly available as an option, and the Public Utility Commission of Hawaii recently announced the nation's first state-wide plan to introduce mandatory TOU rates for most customers.

In the longer run, barriers to the widespread adoption of RTP may not be insurmountable: the lack of predictability can be mitigated as consumers acquire appliances that include communications and control capabilities that facilitate a high degree of automation in electricity consumption, and bill stability can be guaranteed by complementing spot pricing with hedging or insurance products.

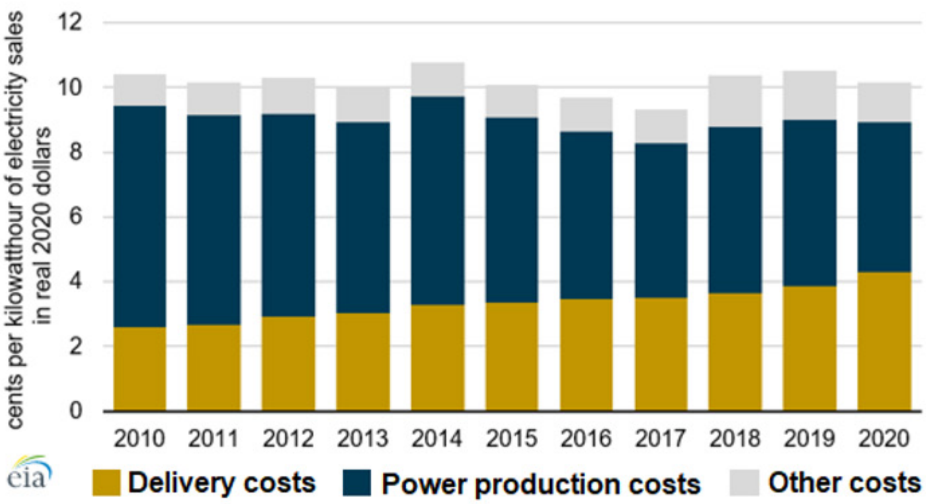
Problem 2: On average, volumetric rates substantially exceed short-run marginal costs.

The left panel in Figure 3 shows the evolution of spending categories of major U.S. utilities between 2010 and 2020. The right panel displays an anonymized bill of a residential consumer in Cambridge, Massachusetts for October 2022. Nearly all the costs incurred by the utility are passed through via volumetric rates in the bill. The total volumetric rate amounts to 0.32 $/kWh. This is nearly twice the charge for generation (0.18 $/kWh), which in turn is higher than typical prices in the relevant wholesale spot market (Boston Hub within ISO New England).

Short-run marginal cost is typically below average total cost because the need for transmission, distribution, and generation capacity is not




Tim Schittekatte, Dharik Mallapragada, Paul L. Joskow, and Richard Schmalensee (2023), "Research Commentary: Economy-Wide Decarbonization Requires Fixing Retail Electricity Rates", CEEPR RC-2023-01, MIT, January 2023.



Service from 10/11/22 - 10/24/22			13 Days	
Meter Number	Current Read	Previous Read	Current Usage	Reading Type
X	75964	75891	73	Actual

Total Charges for Electricity		
Supplier (Eversource) (Basic Svc Fixed)		
Generation Service Charge	73 kWh X .17871	$13.05
Subtotal Supplier Services		$13.05
Delivery		
(Rate 01 R1 RESIDENTIAL)		
Customer Charge (Prorated)		$3.03
Distribution Charge	73 kWh X .07147	$5.22
Transition Charge	73 kWh X -.00177	-$0.13
Transmission Charge	73 kWh X .04437	$3.24
Revenue Decoupling Charge	73 kWh X .00267	$0.19
Distributed Solar Charge	73 kWh X .00341	$0.25
Renewable Energy Charge	73 kWh X .00050	$0.04
Energy Efficiency	73 kWh X .02254	$1.65
Subtotal Delivery Services		$13.49
Total Cost of Electricity		**$26.54**

Figure 3. Left: Breakdown of major U.S. utilities annual spending by category.
Right: Anonymized bill of residential consumer supplied between 10/11/2022 and 10/24/2022 by Eversource in Cambridge, MA.

driven by short-run changes in energy consumption (kWh) but by sustained increases in instantaneous customer demand for power (kW) that in the longer run lead to additional investments in network capacity. In this case, the necessary reform is to lower the average volumetric rate closer to average marginal cost and to increase fixed charges so that the utility's total costs are covered. This sort of reform raises two new issues, however—one related to fairness and another related to long-run efficiency.

In the interest of fairness, Borenstein and co-authors propose to recover system costs that are fixed in the short run via fixed charges that differ among consumers and are tightly linked to ability to pay. Individuals with similar incomes may derive very different benefits from being connected to the electric power system, however; compare a small luxury condo with a large remote villa. Fairness arguments are, as so often, not simple.

However, fixed charges of this sort that are independent of all aspects of electricity consumption cannot provide any incentives for consumers to reduce the need for future investment in network capacity—by, for instance, smoothing usage so their peak demand is reduced. The left panel in Figure 3 shows that network costs have been rising, and we expect this trend to continue due to increases in demand resulting from electrification. To provide incentives to reduce the need for investment, the authors of the *MIT Utility of the Future Study* propose to rely heavily on individualized capacity charges (in $/kW). In theory, each individual customer's capacity charge would reflect the impact of increases in their peak kW demand on the need for future investment in system capacity. Besides the technical challenges involved in computing theoretically correct consumer-specific capacity charges, serious issues of fairness would arise and would conflict with the long-standing regulatory principle of charging the same prices to all consumers in a rate class on a particular transmission and distribution network.

Nonetheless, we believe it is possible to link capacity charges approximately to pressures on investment in system capacity without raising intractable equity issues. Policies of this sort might resemble systems in Spain and some other nations, where consumers in specific geographic areas pay for maximum kW usage in particular time slots. Capacity might be free during the night for the whole year, for instance, while the price per kW might be very high during peak hour periods in the high demand season. Consumers' maximum kW usage is surely positively related to their ability to pay and to the benefits they derive from the power system. This basic approach, tailored to system-specific conditions, seems to us a reasonable compromise between the provision of economic incentives, simplicity, and equity.

Conclusions and a call for action

Getting electricity retail rates right is crucial to affordable and cost-effective economy-wide electrification, which in turn is essential to reaching declared climate goals. As we have shown, current almost entirely time-invariant, volumetrically based electricity rates will make electrification slower and more expensive than it should be. We have shown the general directions reform must take to mitigate this problem, recognizing that the optimal details are likely to differ regionally. This Commentary is a call for action to accelerate research on retail electricity rate design and on deployment of systems that will facilitate rather than hinder economy-wide decarbonization.

Note that an updated version of this commentary was recently published in *Joule*. Read the journal version at the link below:

https://ceepr.link/23RC1J

Research.

Money (Not) to Burn: Payments for Ecosystem Services to Reduce Crop Residue Burning

By: B. Kelsey Jack, Seema Jayachandran, Namrata Kala, and Rohini Pande

Worldwide, poor air quality is a leading preventable cause of death and morbidity. Air pollution reduces the life expectancy of North India's roughly half a billion residents by up to seven years, which represents one of the largest health burdens from pollution in the world.

A major source of air pollution in India is the use of fires to clear agricultural land. Every winter, farmers in North India burn rice stalk (residue) to clear fields. Despite a clear economic case for reducing this pollution, as well as efforts to prohibit and fine those who produce it, agricultural pollution in North India has increased over the last few decades.

Existing policies have failed to account for incentives of two groups of actors: (1) local officials' incentives to enforce penalties when the costs and benefits of polluting activities are in different political jurisdictions, and (2) farmers' incentives to protect the environment given that the costs of pollution are largely borne by others. In our paper, we ask whether a policy that explicitly considers these incentives can reduce pollution.

We investigate the feasibility of Payments for Ecosystem Services (PES) contracts, which pay farmers for not burning crop residue. PES programs raise the private cost of environmental degradation by conditioning cash transfers on avoiding an environmentally harmful behavior. By using a carrot rather than a stick, PES avoids the political challenges of fines. By placing the incentive on the desired outcome rather than the input, PES is a more flexible approach than equipment subsidies.

However, contextual and institutional factors may limit the efficacy of PES—and, more broadly, conditional cash transfers—in low and middle-income countries such as India. PES participants must undertake a costly action to comply with the program and receive payment. Farmers may not comply if they do not trust that the conditional payment will be made. They may also fail to comply if they lack cash on hand to pay for alternatives to burning before receiving the PES payment. Both of these factors may limit PES efficacy.

PES contracts that offer partial payment in advance may help with trust and liquidity. An upfront payment can increase trust that a subsequent conditional payment will occur. It can also alleviate liquidity constraints when farmers need to spend money on alternatives to burning.

However, recouping the upfront payment if the participant fails to comply is frequently infeasible or undesirable in low-income settings. Practically, upfront payments must then be unconditional, potentially undermining their usefulness for at least two reasons. First, offering a portion of the total payment upfront and unconditionally lowers farmers' marginal incentives to comply because the conditional payment is smaller. Second, upfront payments reduce cost-effectiveness due to payments to non-compliant farmers. Hence, the net effect of upfront and unconditional payments on compliance and cost-effectiveness is ambiguous.

Motivated by these observations, we conducted a randomized controlled trial in 171 Punjabi villages during the 2019 rice growing season to compare the efficacy of standard PES and partial upfront PES. We compare three farmer groups: (1) those who did not receive a contract (control), (2) those who received a contract with payment conditional on verification that the farmer did not burn (standard PES), and (3) those who received a contract with a partial upfront payment that was (explicitly) unconditional on compliance, with the remainder conditionally paid after verification (upfront PES).

Our main finding is that upfront PES led to a 10% higher contract compliance than standard PES—a doubling of the compliance rate. Remote sensing estimates of burning are consistent with the contract compliance results. We see a roughly 10% lower rate of burning among farmers offered upfront PES versus standard PES. The remote sensing measure also reveals that standard PES had no effect on burning when compared to the control group. This indicates that standard PES payments were inframarginal, i.e., paid to farmers who would not have burned even without PES. The upfront PES effect size corresponds to a 50-80% higher rate of not-burning than in the standard PES arm or control group.

Why did partial upfront contracts outperform standard PES contracts? For insight, we examine farmer responses to endline survey questions about the role of cash constraints and trust in determining their PES program response. Farmers assigned to the upfront PES treatment have 6.8% higher trust that contract payments will be made than those assigned to standard PES. Around 70% of farmers say cash on hand affected their crop residue management decisions, suggesting that this was an important overall constraint. However, responses about cash on hand did not differ by treatment. In contrast, heterogenous estimates by baseline levels of general (rather than PES program-specific) liquidity and trust do not support either mechanism explaining the relative efficacy of upfront PES. Overall, we take these results as suggestive evidence that trust may be the mechanism affecting the relative success of upfront payments.

To evaluate the cost-effectiveness of PES programs, we compare PES costs with the benefits of reduced residue burning. We first calculate the cost-per-additional-acre-not-burned for the two treatments using our remote sensing-based outcome. Standard PES has no statistically significant impact on burning. Upfront PES, on the other hand, reduced burning and the cost-per-additional-acre-not-burned (see Figure 1 below). Despite noncompliance from a substantial portion of farmers paid upfront, the estimated cost of the program is drastically lower than our rough per-acre mortality benefit estimate ($7,600).

B. Kelsey Jack, Seema Jayachandran, Namrata Kala, and Rohini Pande (2023), "Money (Not) to Burn: Payments for Ecosystem Services to Reduce Crop Residue Burning", CEEPR WP-2023-05, MIT, February 2023.

These results show that crop residue burning can be reduced through well-designed PES payments. Our design, which take institutional constraints and farmer concerns into account, can significantly improve efficacy. Providing a portion of the contract payment upfront results in larger reductions in burning than providing the entire payment after participants have completed costly behavior change. Despite higher "wasted" payments (to farmers who continue to burn), PES with upfront payments is still cost-effective. It results in burning reductions that provide benefits far in excess of their cost.

PES programs provide reasons for optimism. Such programs are appealing because they can be implemented by organizations that want to reduce fires but lack the authority to levy fines. Furthermore, in the future, the need for upfront payments might become less important as trust in being paid grows. The enormity of the environmental damage caused by crop residue burning in India justifies investment in PES programs and highlights the need for further research to find viable solutions to this problem.

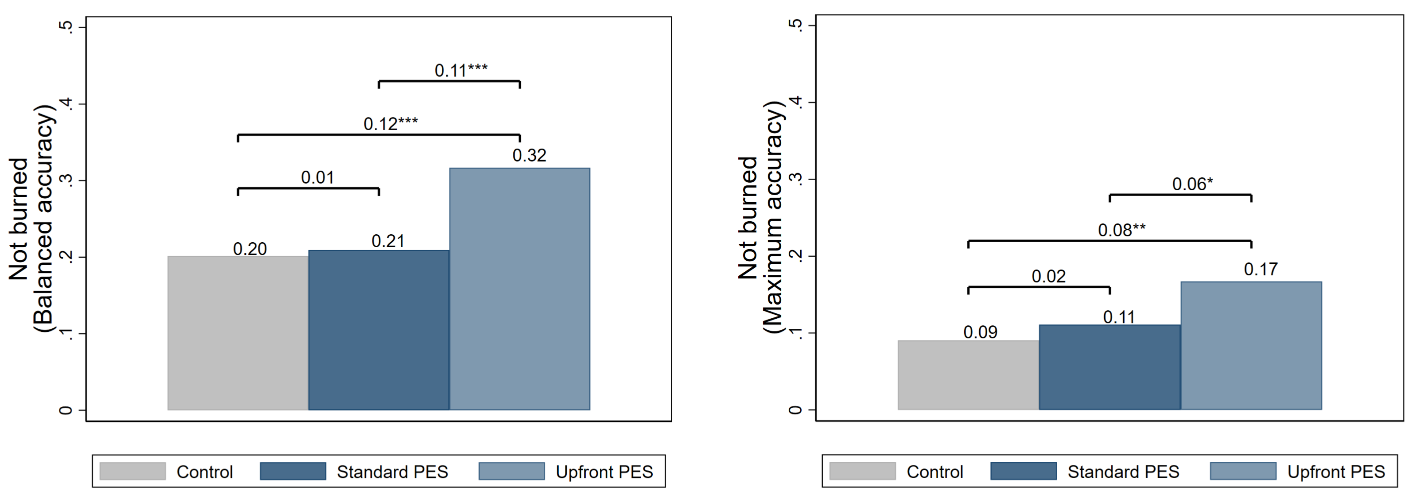


Figure 1. Impact on Burning by Different Treatment Groups Using Two Machine Learning Models

Nathan Delacrétaz, Bruno Lanz, Amir H. Delju, Étienne Piguet, Martine Rebetez (2023), "Impacts of Rainfall Shocks on Out-Migration in Türkiye are Mediated More by Per Capita Income than by Agricultural Output", CEEPR WP-2023-08, MIT, March 2023.



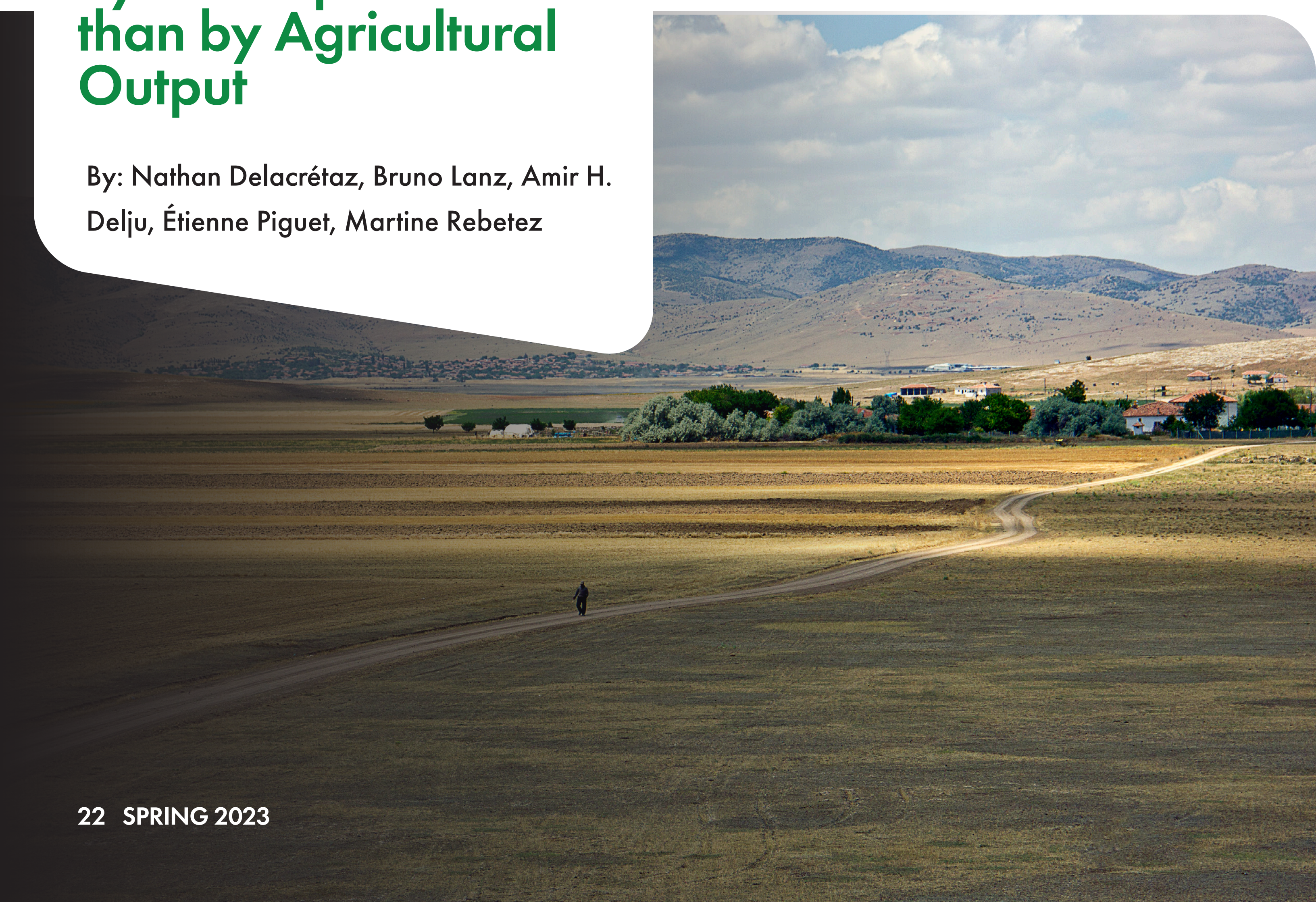


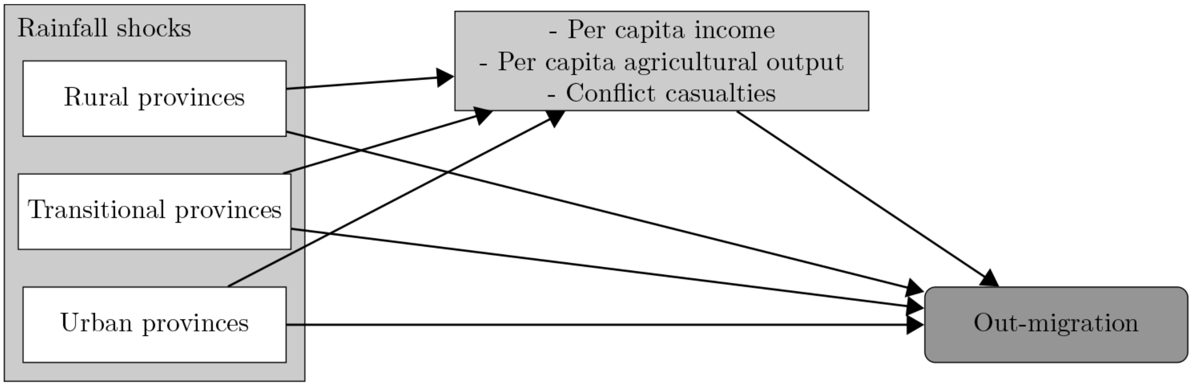
Research.

Impacts of Rainfall Shocks on Out-Migration in Türkiye are Mediated More by Per Capita Income than by Agricultural Output

By: Nathan Delacrétaz, Bruno Lanz, Amir H. Delju, Étienne Piguet, Martine Rebetez

Migration decisions are increasingly studied as an adaptation response to climate change and empirical evidence is important to quantify its relevance for policy decisions. Building on farm-level studies documenting the role of extreme weather events as a key detrimental determinant of agricultural yields (e.g., Schlenker and Roberts, 2009; Burke and Lobell, 2010), the objective of our work is to understand how random deviations from long-run precipitation patterns act as a push factor in migration decisions in societies with a predominantly rural population.





Note: Arrows illustrate causality paths between variables.

Figure 1. Causality Paths from Rainfall Shocks to Out-Migration

Our work contributes to research trying to identify the mechanisms linking climate shocks and migration, and we focus on three channels through which rainfall shocks affect out-migration. First, per capita GDP captures economy-wide impacts that ripple local economic activities, including (but not limited to) agriculture, and ultimately affect populations living in rural regions. Second, agricultural GDP per capita may be directly affected by climate shock through agricultural yields, thereby acting as a push-factor, but it may also induce a poverty trap which prevents populations from migrating (Cattaneo and Peri, 2016). Lastly, we document how rainfall shocks affect local conflicts, which in turn may affect the extent of migration out of a given province. Figure 1 illustrates how we decompose the direct effect of rainfall shocks on out-migration across various channels.

To document these effects, we exploit 2008–2018 provincial-level data for Türkiye, a middle-income country with a large share of predominantly rural regions. We characterize the extent to which yearly rainfall deviates from a long-run local distribution of precipitation by a standardized precipitation index (SPI), allowing us to control for differences in long-run distribution of rainfall across space. We further exploit the longitudinal dimension of the data to introduce fixed effects in the analysis and control for the fact that rural regions tend to experience higher out-migration on average and account for temporal trends in rural to urban migration.

Our results show that years subject to below-average SPI (drought) imply higher out-migration from rural areas. Quantitatively, a negative SPI shock of one standard deviation in the long-run distribution of rural provinces is associated with a 3% increase in yearly migration out of rural provinces. We then show that negative SPI shocks imply a reduction of economy-wide output in rural areas, which in turn acts as a push factor triggering out-migration. This corresponds to around 26% of the direct effect of SPI shocks on out-migration in rural provinces.

By contrast, we do not find significant evidence that per capita agricultural GDP is a channel at the average of the sample. In fact, our data suggest that the agricultural GDP is only a relevant channel for provinces that are in the upper quartile of crop production. Importantly, while the agricultural channel plays a role through crop production, it is only relevant for a small share of provinces that rely heavily on these crops, rather than for rural provinces in general.

Lastly, we show that the number of conflict fatalities in rural regions tends to increase with droughts, and that conflicts act as a push factor. In rural provinces, around 8% of the total effect of SPI shocks on out-migration can be attributed to conflicts. This suggests that a "conflict channel" operates in parallel to the direct effect of SPI shocks on out-migration and hinges upon contextual and institutional factors (Abel et al., 2019).

One interpretation of our results is that provinces with low level of urbanization are more exposed to climate variability, making it more likely that precipitation shocks will act as a push factor in migration decisions. However, we emphasize that the mechanism that links droughts and migration in rural areas is more complex than a simple impact on the agricultural sector. One possible explanation is that price fluctuations for crops can impact other sectors of the local economy. In turn, for provinces with relatively high crop production and where the agricultural sector constitutes a larger share of the local economy, agricultural GDP is more directly affected by fluctuations in the SPI. Further research is needed to confirm this interpretation.

Furthermore, our analysis shows that conflicts also increase with droughts and play a role as a push factor in out-migration decisions, which is consistent with evidence from other contexts (Kelley et al., 2015; Missirian and Schlenker, 2017; Schutte et al., 2021; Eklund et al., 2022). This suggests that droughts give rise to separate channels through per capita GDP and conflicts. Taken together, more frequent droughts can be expected to increase out-migration in rural areas, both by affecting economy-wide activities and through conflicts. Making local economies more resilient to rainfall shocks, through local adaptation strategies or economic transfers, might help mitigate the impact of increased rainfall variability expected from future climate change.

We close by emphasizing that our data have not allowed us to document destination choices in relation to rural out-migration. Whether out-migration from rural provinces hasten urbanization, lead to rural-rural displacements, or induce international displacements, remains an open question.

Research.

Temperature and Cognitive Performance

By: Benjamin Krebs

Boston suffered from a tremendous heat wave last summer. Both in July and August temperatures rose beyond 90°F (32°C) for six consecutive days. The city declared a heat emergency and advised citizens to stay indoors. Temperatures above 90°F are a severe threat to human health. Extended exposure may lead to cardiovascular problems, or even death. Disconcertingly, climate change models predict such heat waves to become more frequent and to last over longer periods of time.

Emergency room admissions and heat fatalities are an extreme outcome of heat waves and, fortunately, a relatively small share of U.S. residents experiences them. But hot temperatures affect humans in other, more subtle dimensions, which are less severe but affect a broader population. One example is cognitive performance, which is central to any human activity, an input to our labor productivity, and vital in our everyday lives. It is therefore essential to understand how temperature impacts cognitive performance, and how climate change affects this relationship.

In this paper I estimate the effect of temperature on cognitive performance using data from an online mental arithmetic training game called Raindrops, played on the Lumosity platform. The dataset I use contains more than 31,000 residents from the contiguous United States, who played 1.15 million times in total. I know approximately where and when people used the software. That allows me to match their performance with weather data from the National Centers for Environmental Information surface database. I run regression analyses with the average temperature during the 24 hours preceding a play as the main explanatory variable.

Mental arithmetic performance not only depends on temperature but also on many other things. Indeed, in my data people living in colder regions of the country perform better on average than people living in hotter regions. This might be due to factors that are completely independent of the weather. To account for that, I subtract each individual's mean performance from their scores—I run what economists call fixed-effects regressions. This essentially amounts to comparing the individuals to themselves under different temperature exposures, instead of comparing people to each other. This is possible due to the data structure, where I observe each individual many times. In the regression analyses I further control for a variety of play characteristics and weather variables.

The results in Panel A of Figure 1 show that people do experience a performance drop when temperatures are high. The points represent the coefficients from the regression on different temperature bins and the gray area depicts the confidence interval. Relative to the optimal temperature of around 16.5°C (62°F), players score about 0.48 (0.7%) fewer points when temperatures are between 21 and 24°C (70–75°F), and about 0.95 (1.5%) fewer points when they are above 27°C (81°F). I do not observe any statistically significant effects for cold temperatures.

There is an important heterogeneity in these results: Panel B of Figure 1 shows that people living in colder regions seem to respond much more to high temperatures. Their score decreases by 1.82 (2.7%) on days above 27°C (81°F), while the score of people living in hotter regions only drops by 0.45 (0.7%). This points to the role of adaptation. As hotter regions experience such temperatures more frequently, they are better equipped to attenuate their consequences. For example, in places that are hotter on average, a higher share of households has air conditioning.

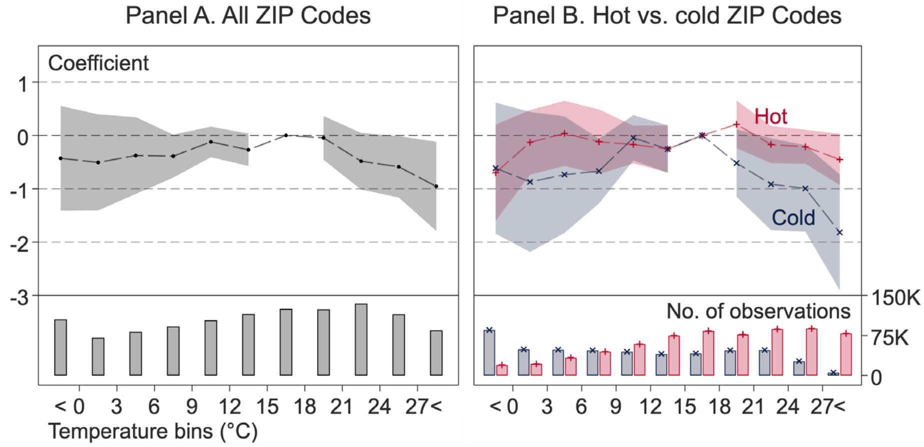


Figure 1. Air temperature and cognitive performance: 3°C-bins regressions.

Notes: Coefficients with 95% confidence intervals (left y-axis), and number of observations (right y-axis) from regressions of the number of correct answers on 3°C-bin indicators of the average air temperature during the 24 hours preceding the play (x-axis). The standard errors are clustered on ZIP Codes. The reference bin is 15–18°C. The regression in Panel A includes all observations. Panel B shows the results from separate regressions for the cold-ZIP Codes sample (below-median 2015–2019 average temperatures), and the hot-ZIP Codes sample (above-median 2015–2019 average temperatures). The control variables include individual effects, time effects, play controls, and weather controls.

Consequently, as temperatures rise, one should expect an increase in air conditioning in colder places. Does that mean that heat waves will be less of a problem in the future due to this adaptation? Unfortunately, climate change not only leads to adaptation but also to intensification. Heat waves will become even hotter and stretch over more consecutive days. Figure 2 shows that, if average temperatures are above 21°C (70°F) for multiple days, the effect gets worse. While the performance drop in hotter regions is still smaller than in colder regions, the effect nonetheless increases with the number of consecutive hot days. Thus, climate change will probably worsen the effect even in well-adapted regions.

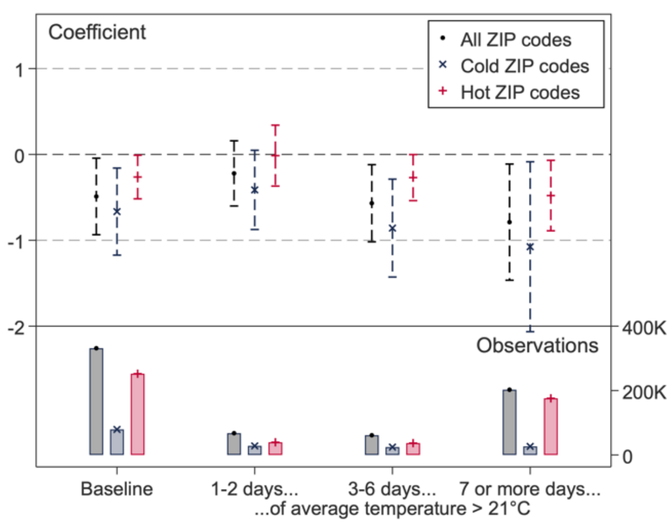


Figure 2. Effect accumulation.

Notes: Coefficients with 95% confidence intervals (left y-axis), and number of observations (right y-axis) from regressions of the number of correct answers on an indicator = 1 if the average temperature was above 21°C during different temporal periods before a play (x-axis). The standard errors are clustered on ZIP Codes. The baseline is 24 hours preceding a play. The reference is a day with an average temperature below or exactly 21°C. I run separate regressions for all observations, the cold-ZIP Codes sample (below-median 2015–2019 average temperatures), and the hot-ZIP Codes sample (above-median 2015–2019 average temperatures). The control variables include individual effects, time effects, play controls, and weather controls.

My research is part of a growing literature that addresses the social and economic consequences of climate change. In the realm of cognitive impairments, a couple of papers have analyzed how temperature affects adolescents during important exams (e.g., Graff Zivin et al., 2020; Park et al., 2020; Park, 2022). While understanding the role of environmental factors in this context is highly relevant, individuals are potentially much more sensitive to these factors when they find themselves in this particularly stressful, non-everyday situation. My study complements these findings. I investigate temperature impacts in a familiar environment, representative of everyday situations. This context gives insight into how temperature affects us all on a daily basis.

Benjamin Krebs (2022), "Temperature and Cognitive Performance", CEEPR WP-2022-019, MIT, December 2022.

Gunther Glenk, Philip Holler, and Stefan Reichelstein (2023), "Advances in Power-to-Gas Technologies: Cost and Conversion Efficiency", CEEPR WP-2023-09, MIT, April 2023.



Research.

Advances in Power-to-Gas Technologies: Cost and Conversion Efficiency

By: Gunther Glenk, Philip Holler, and Stefan Reichelstein

In the intensifying debate about alternative pathways for rapid decarbonization, hydrogen is increasingly viewed as a critical building block for storing and flexibly dispatching large amounts of carbon-free energy. Among alternative hydrogen production technologies, Power-to-Gas (PtG) in the form of electrolytic hydrogen has received particular attention. Large-scale deployment of these technologies, however, is generally expected to hinge on substantial cost declines and energy conversion improvements. To accelerate the pace of these improvements, governments around the world have recently introduced sizeable regulatory initiatives and subsidy programs for the development, deployment, and manufacturing of hydrogen equipment.

This paper projects cost and conversion efficiency improvements for three prevalent PtG technologies: alkaline, polymer electrolyte membrane (PEM), and solid oxide cell (SOC) electrolysis. Our analysis is grounded in a learning-by-doing model that postulates that system prices for electrolyzers and their conversion efficiency decline at a constant rate with every doubling of cumulative installments of the technology in question. Such learning models have proven highly descriptive in the context of solar photovoltaics, onshore wind turbines, or lithium-ion batteries. Scarcity of data has so far limited the estimation of learning curves to alkaline electrolysis or to a single equipment manufacturer. Some earlier studies estimate the rate of past cost declines of PtG technologies against time or rely on expert opinions about future cost developments.

Our analysis provides a comprehensive assessment of the dynamics in system prices and energy efficiency for the three PtG technologies by tracking global observations on investment expenditures and energy consumption. This information is linked to capacity installations at facilities commissioned worldwide between 2000–2020. Our estimates return significant and robust learning curves for system prices in the range of 83–86% (Figure 1). Thus, system prices declined by 14–17% compared to the price levels prior to the doubling of cumulative installments. The relatively young SOC technology is projected to show the sharpest price decline at a 17% learning rate. PEM electrolyzers, in contrast, have experienced high capacity growth and a rapid price decline between 2003 and 2020. Here, our estimates yield a relatively slow learning rate of 14%. For conversion efficiency, we estimate that every doubling of cumulative installed capacity reduces the required

kilowatt-hours (kWh) per kilogram (kg) of hydrogen produced by approximately 2% across all three technologies.

Our regression results can be extrapolated to yield forecasts for the system prices and conversion efficiencies of the three PtG technologies in question by the year 2030. Even for divergent growth forecasts issued by different industry and policy sources, the extrapolated values fall into a relatively narrow range. Specifically, our calculations project ranges for system prices by 2030 of \$285–475/kW for alkaline, \$225–352/kW for PEM, and \$441–767/kW for SOC electrolysis. Regarding the energy consumption of PtG systems, our projections for 2030 yield ranges of 47–49 kWh/kg for alkaline, 47–50 kWh/kg for PEM, and 36–38 kWh/kg for SOC technology. Compared to earlier estimates articulated by industry experts, technical reports, and academic studies, our projections are consistently and substantially below most earlier estimates. While this can be attributed to multiple factors, the most important one is that our projections model technological progress not as an exogenous function of time but as an endogenous process driven by deployment rates.

Recognizing the potential of hydrogen as a decarbonized energy source, the U.S. Department of Energy articulated the *Hydrogen Shot* initiative in 2021. According to this initiative, the cost of producing hydrogen is to come down to \$1.0/kg by the year 2030. The system prices and conversion efficiencies we forecast are useful in gauging whether or not the U.S. Department of Energy's goal appears to be a long shot. Depending on the growth of capacity installations, our calculations yield estimates for the life-cycle cost of electrolytic hydrogen production in the range of \$1.6–1.9/kg by 2030. These findings lead us to conclude that the *Hydrogen Shot* target by the U.S. Department of Energy of producing clean hydrogen at a cost of \$1.0/kg by 2030 is ambitious but not unrealistic. Because electricity prices will become the dominant component of the life-cycle cost of hydrogen by 2030, the attainment of the *Hydrogen Shot* target via electrolytic hydrogen ultimately hinges on the availability of inexpensive and clean electricity.

Our findings on the economics of electrolytic hydrogen speak directly to several recent policy initiatives. We first note that even our most ambitious growth scenario for electrolyzer deployment falls significantly short of the target for 2030 by the International Energy Agency (IEA). As part of its "Net-zero by 2050" scenario, the IEA postulates 850 GW of installed capacity by 2030 and 3,000 GW by 2045. Furthermore, most data points underlying our projections were set prior to the recent hydrogen initiatives by the European Union and the Inflation Reduction Act in the United States. The production tax credit of up to \$3.0/kg of clean hydrogen available under the Inflation Reduction Act is likely to advance the deployment growth of PtG systems significantly in the United States. This growth will be reinforced by the goal of the European Union, which seeks to induce its member states to collectively produce 20 million tons of green hydrogen annually by the year 2030.

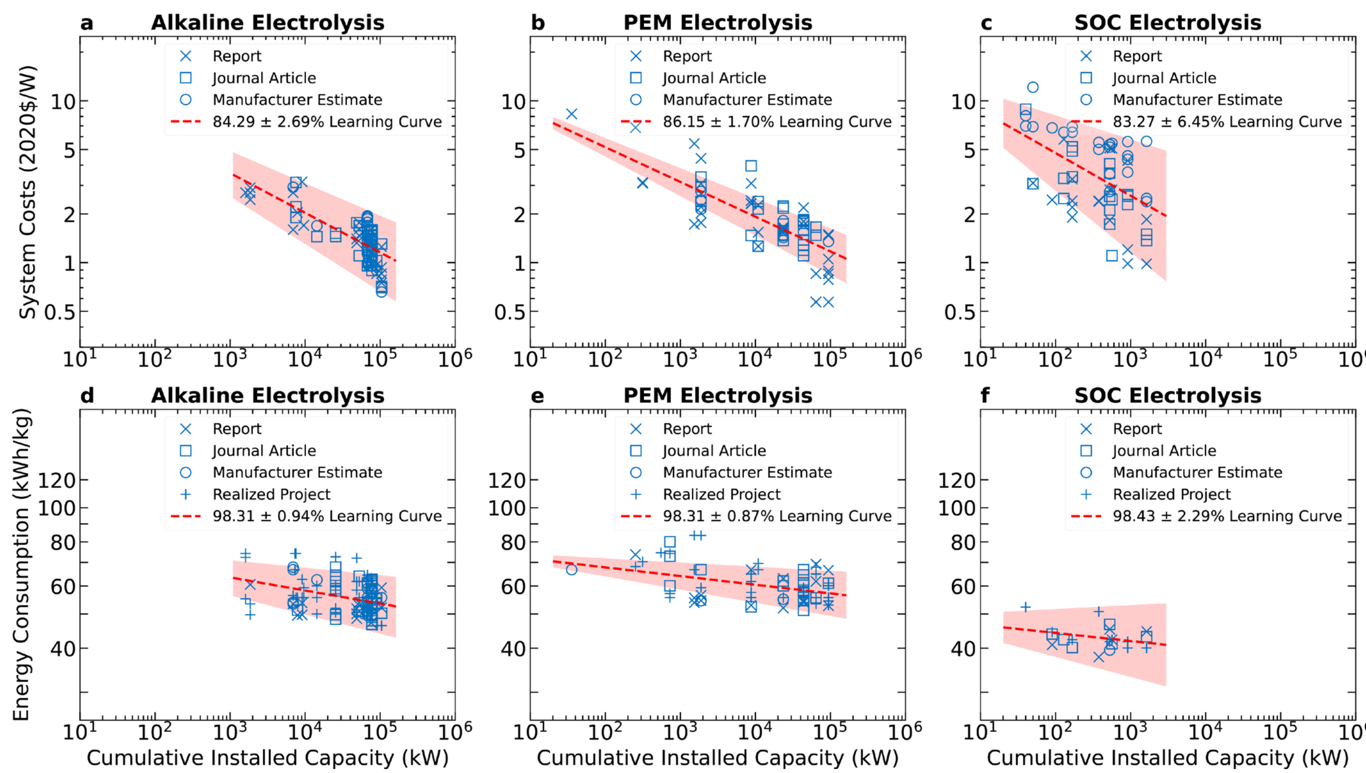


Figure 1: Estimates of learning curves.

This figure plots the global system prices in 2020 \$US against the global cumulative installed capacity together with our estimates of the corresponding learning curves for (a) alkaline, (b) PEM, and (c) SOC electrolyzers. The figure also plots the energy consumption against the global cumulative installed capacity together with our estimates of the corresponding learning curves for (d) alkaline, (e) PEM, and (f) SOC electrolyzers. Areas shaded in red represent 95% confidence intervals.

Santiago Andrade Aparicio and John E. Parsons (2023), "Exploring a Suitable Business Model for Nuclear Batteries", CEEPR WP-2023-06, MIT, March 2023.

Research.

Exploring a Suitable Business Model for Nuclear Batteries

By: Santiago Andrade Aparicio and John E. Parsons

A nuclear battery is a stand-alone, plug-and-play energy platform combining a micro-reactor of 1–20 megawatts electric and a turbine to supply electricity and heat from a very small footprint. The development of nuclear batteries opens up new opportunities for the utilization of nuclear power. Its small size and portability enable delivery of energy off-grid, for example to remote communities or mines. Its inherent safety combined with its energy density make it an ideal low carbon replacement for on-grid fossil fuel-fired combined heat-and-power plants and other distributed generation co-located at industrial and commercial facilities. It can be sited downstream of transmission congestion, expanding capacity for data centers, EV charging stations and other large load sources. Nuclear batteries can also be used as emergency energy sources where the grid has been temporarily disabled (Black et al. 2022).

Alongside the technological innovation required to realize the nuclear battery, innovation in the business model may also be required to drive deployment in these new use cases. The nuclear industry's existing business model evolved around the installation and operation of very large, light water reactors supplying on-grid electricity in bulk. This paper explores how a business model for nuclear batteries may differ from the legacy nuclear model. For inspiration, we look to the business model currently used for the deployment of fossil fuel-fired distributed generators, which the nuclear battery may supplant. Some elements of that business model can be ported over to a business model for nuclear batteries. However, there are differences in the technologies that will force innovation in that model, too.

We organize our discussion of business models using the Business Model Canvas of Osterwalder and Pigneur 2010. The Canvas is composed of nine different building blocks: Key Activities, Key Partners, Key Resources, Cost Structure, Value Proposition, Customer Segments, Customer Relationships, Channels, and Revenue Streams. Together, these describe "how an organization creates, delivers and captures value."

We draft a proposal of a business model for a nuclear battery Solution Provider company. This business model is displayed through the Business Model Canvas and is intended as a thought-generating tool for readers to reflect, critique and edit.

Key Partners: describes the network of suppliers and partners that make the business model work.

The Solution Provider and its operating model will rely heavily on partnerships with private and public entities. The Developer/Manufacturer of the nuclear battery is the single most crucial supplier. Additionally, the fuel supplier is also a critical link to the functionality of the nuclear battery. Moreover, public entities like regulators (NRC in the US), and local, state, and federal governments, are crucial non-technical partners that will license and permit the use of nuclear batteries. Finally, the Solution Provider will also have to prioritize its relationships with activists and lobbyists to address the hurdle for nuclear energy to achieve social capital.

Key Activities: describes the most important things a company must do to make its business model work.

The Solution Provider will oversee purchasing all the equipment, diagnosing, and providing a solution to the Customer, siting the equipment, fueling the nuclear battery, and transporting it to the site. After this, the company still needs to install the nuclear battery, operate it for the duration of the agreed-upon timelines, with an incredibly high level of reliability and safety, and provide monitoring of the asset.

Key Resources: describes the most important assets required to make a business model work.

Many physical assets are needed for this business to run smoothly, including a fleet of Nuclear Batteries, a transportation fleet, and fuel contracts. However, in addition to Human Capital, there are also significant non-physical resources that are crucial for the company to produce value, such as nuclear licenses and software.

Cost Structure: describes all costs incurred to operate a business model.

The costs incurred in this business fall within three categories: (1) Capital Expenditures including the purchase of the nuclear battery fleet, transportation equipment, software licenses, nuclear licenses, and real estate; (2) Operational Expenditures including labor costs, fuel costs, service, and maintenance; (3) Sales, General & Administrative.

Value Proposition: describes how a company communicates with and reaches its Customer Segments to deliver a Value Proposition.

The key differentiator of this technology will be the carbon-free heat and power on-site. Its additional value propositions include an economically attractive solution that is readily deployed (plug-and-play) and that can be modularized to serve the specific Customer need. Furthermore, it poses a safe and secure holistic solution to the Customer with an incredibly small land footprint that can improve the overall Environmental, Social, and Governance metrics of the user. Finally, it can be imagined that the Solution Provider might be able to generate energy efficiency insights than can be offered to the Customer to create additional value.

Customer Relationships: describes the types of relationships a company establishes with specific Customer Segments.

This building block shares several aspects with nuclear power plants and fossil fuel-fired distributed generators. However, because in the nuclear battery enterprise assets are not owned or operated by the Customer but rather by the Solution Provider, some differences in the relationship they have are bound to happen.

Customer Segments: defines the different groups of people or organizations an enterprise aims to reach and serve.

This technology can service a variety of customers across industries and locations. We propose a four-category approach to understand better what markets are being served and which are the expected players in each segment: (1) Off-grid Heat and Power: Industries such as mining, industrial processing, military bases, and microgrids require both electricity and heat to operate. They can leverage the nuclear battery as a carbon-free source of both inputs. (2) On-grid Heat and Power: Clients such as some industrial processes, educational or corporate campuses, and hospitals require a primary system to provide clean electricity. Once they have the electricity provided by a nuclear battery, it will be more economically attractive to leverage the heating power instead of getting that resource from a different provider. (3) Off-Grid Temporary: This segment will leverage the mobility and dispatchability of the nuclear battery only for a limited amount of time. Instances of this may include emergency relief, energy demand spikes in remote areas, or military applications. (4) On-Grid Temporary: this customer base is expected to be the smallest, with applications imagined substituting power for significant overhauls of other generation sources or large construction projects.

Channels: describes how a company communicates with and reaches its Customer Segments to deliver a Value Proposition.

Business-to-business, business-to-business-to-business (out-sourced), and government partnerships are imagined to be the most prominent communication channels. Additionally, web services, sales representatives, advertising, and conference/exposition attendance can be relevant to secure new partnerships and clients.

Revenue Streams: represents the cash a company generates from each Customer Segment.

The Solution Provider will generate cash in different ways depending on the type of service they provide. For example, suppose they service a mine for ten years. In that case, we can expect there to be an initial Lump Sum charged to the Customer to cover the fixed costs, plus a variable rate for the energy produced, which may or may not be tied to other variables such as nuclear fuel prices or electricity prices. On the other hand, for temporary purposes, the enterprise may simply charge a contract value to the customer. The Solution Provider will have the data to draw insights regarding energy efficiency and may sell those to the customer in a consultancy/advising package.

The challenge of decarbonization will require deployment of a variety of new technologies such as nuclear batteries. The technological changes must be accompanied by changes to the business models used to deploy these technologies. The business model discussed here for nuclear batteries needs to be fleshed out in a variety of ways. Significant research and understanding need to happen on the regulation side that focuses on the licensing of serially manufactured reactors, the transportation of the technology, and the usage in urban settings. Additionally, a financial structure and economic analysis need to understand how and if this entity can be profitable in the expected markets.

Key Partners

- Developer/Manufacturer
- Regulator
- Fuel Supplier
- Government (Local, State and Fed)
- Activists, Lobbyists

Key Resources

- Nuclear Battery Fleet
- Transportation Fleet
- Licenses
- Fuel Contracts
- Digital Capabilities
- Emergency Response

Key Activities

- Procurement
- Solution Design
- Siting
- Transportation & Installation
- Fueling & De-fueling
- Operation & Monitoring
- Service & Maintenance
- Billing & Contracts

Value Proposition

- Carbon free heat and power
- Economically Attractive
- Plug & Play
- Dispatchable
- Modularizable
- Safe & Secure
- Holistic Service (minimum Customer involvement)
- Dense energy (low area footprint)
- ESG improvement
- Energy Efficiency Consultation Services

Customer Relationships

- Customer Service
- Efficiency tracking and improvement
- Centralizer owns and operates asset that customer benefits from

Channels

- B 2 B
- B 2 B 2 B (outsourced)
- B 2 Government
- Webpage, Advertising, Sales Reps, Conferences /Expos

Customer Segments

Off-grid Heat and Power
- Mining
- Industrial Processes
- Microgrids
- Military

On-Grid Heat and Power
- Hospitals
- Campus
- Industrial Processes

Off-grid Temporary
- Emergency Relief
- Demand spikes
- Military

On-Grid Temporary
- Overhaul substitution
- Large construction

Cost Structure

CapEx
- Nuclear Batteries
- Transportation Fleet
- Real State (HQ and ops center)
- Operation Software
- Licenses

OpEx
- Labor costs
- Fuel costs
- NB maintenance and service
- In-house maintenance and service
- Distribution

SG&A
- Sales
- Finance
- Mgmt.
- Legal
- Accounting
- HR
- Customer Service
- Billing
- Marketing

Revenue Streams

- Lump Sum (incl. Diagnostic, Solution Design, Licensing, Transportation and Installation) – or through routinely payments: Objective is to recover CapEx
- Variable Fee (USD per kWh) – could be tied to nothing or to electricity prices in the region or nuclear fuel prices, etc.
- Fixed Contract Value for Temporary applications
- Energy Consulting Services

Figure 1: Proposed business model for nuclear battery Solution Provider

Paul Waidelich and Bjarne Steffen (2023), "The Role of State Investment Banks for Renewable Energy Technologies in OECD Countries", CEEPR WP-2023-07, MIT, March 2023.

Research.

The Role of State Investment Banks for Renewable Energy Technologies in OECD Countries

By: Paul Waidelich and Bjarne Steffen

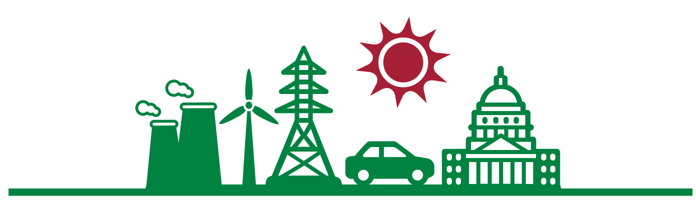
State investment banks (SIBs), i.e., publicly funded financial institutions with a domestic focus, exist in nearly all OECD member countries and are increasingly used to finance the energy transition. Notably, this trend involves jurisdictions that traditionally lean towards less government intervention, such as the United Kingdom or Australia. Most recently, the U.S. Environmental Protection Agency has been exploring whether to capitalize a national green bank using parts of the Inflation Reduction Act's Greenhouse Gas Reduction Fund. Qualitative studies have motivated the use of SIBs with their capacity to finance projects that struggle to source funds from the private sector, such as small-scale projects or those that use less established technologies. In addition, SIBs can mobilize private capital by vetting projects and signaling their commercial viability to potential co-lenders. However, the potential deficiencies of state-owned banks, such as lower efficiency and politically distorted decision-making, are well-known. As a result, it remains unclear if the actual financing patterns of SIBs justify their popularity among policymakers.

To fill this gap, we derive hypotheses on the optimal financing behavior of SIBs from the energy policy literature. To test them, we identify SIB lenders in a sample of 4,999 transactions between 2004–2021 for new renewable energy (RE) projects in OECD member countries. Importantly, our sample covers multiple RE technologies at different stages of maturity, including solar photovoltaics and concentrated solar power, onshore and offshore wind, biomass and waste, geothermal, and small hydro. Using a fixed effect regression model, we estimate the predictors of whether a transaction involved debt financing by one or multiple SIBs, such as the deal size or the market maturity of the financed technology. This allows us to identify what differentiates transactions with SIB involvement from other deals, which are overwhelmingly financed by commercial banks, and whether this aligns with what the academic literature suggests.

We find that in OECD countries, SIBs' lender activities involve 11% of RE transactions and is about two times larger than for all other public sector entities combined, which illustrates their increasingly significant role in financing renewables around the globe. SIBs are more likely to appear in deals for higher-risk technologies, an effect that is most pronounced for offshore wind where SIBs are involved in almost 75% of transactions. For solar photovoltaic plants, whose risk profile has improved considerably over the last two decades, our results indicate that SIBs reduce their financing activities once the technology matures in the respective country. Although SIBs feature regularly on the first transactions providing debt to a novel technology in a country, their activity as "first-mover" is outperformed by other public sector lenders, such as export credit agencies, government ministries, or, for Latin-American OECD countries, development banks.

Contrary to the notion that SIBs should deliberately support smaller projects, we find that their involvement increases in transaction size. This could result from political biases in favor of prominent large-scale RE projects, or from the incentives of SIB managers and staff being misaligned with the policy objective of enabling smaller-scale (but more laborious and potentially less profitable) RE projects. Regarding the question of mobilizing private capital, our results paint a mixed picture. On the one hand, we find that SIBs often operate as sole lenders, particularly for projects sponsored by public sector entities. On the other hand, we find that SIBs' involvement as a co-lender in bank syndicates correlates weakly with a larger syndicate size, in line with extant studies from the empirical finance literature.

Our results highlight the potential of SIBs for policymakers that are considering revising the mandate of existing institutions or establishing new green banks to foster the energy transition. In realizing the potential of SIBs for the clean energy transition, decision-makers should make sure that the SIB's mandate and guidelines are effective in enabling smaller RE projects if that is a policy objective, and pay attention that either SIBs or other public sector lenders deliberately target market-opening projects that deploy novel technologies. Furthermore, we suggest that policymakers should consider mandating or incentivizing SIBs to withdraw from sufficiently mature technologies if they no longer struggle to obtain debt financing from the private sector. Overall, our analysis adds to the understanding on how SIBs can complement other policy instruments as part of an effective climate policy strategy, supporting policymakers that aim to foster the clean energy transition.



Introducing the MIT Climate Action Through Education Program

By: Aisling O'Grady

The MIT Climate Action Through Education (CATE) program, directed by Professor Christopher R. Knittel, is developing an MIT-informed interdisciplinary, place-based climate change curriculum for U.S. high school teachers in the following core disciplines: History/Social Science, English/Language Arts, Math, and Science.

Curricular materials—labs, units, lessons, projects—will be aligned with relevant U.S. education standards and tailored to each U.S. state. The solutions-focused curriculum will inform students about the causes and consequences of anthropogenic climate change, while equipping them with the knowledge and sense of agency needed to contribute to climate mitigation, adaptation and resilience. Topics include, but are not limited to: Environmental Justice, the Greenhouse Effect, the Industrial Revolution, UN Sustainable Development Goals, household energy use, and the cost of solar and battery storage over time. Each lesson, lab, unit, or project can be used as a standalone, with time commitments ranging from half a class period to a month.

The keystone of the materials will be the incorporation of MIT resources and research, such as:

- The Energy Initiative's Future Of Studies
- Professor Knittel's work on household carbon footprints
- The Environmental Solutions Initiative's Digital Climate Primer and TILclimate podcasts

Materials will also feature:

- Place-based learning components
- An emphasis on climate solutions
- Integration with leading U.S. education standards, like NGSS and Common Core
- Options for integration across disciplines, with other lessons

The free, openly accessible curriculum will launch in Fall 2023. It is written by practicing high school teachers and incorporates feedback from teachers, students, and MIT researchers.

Our work is informed by our nationwide survey of over **100** high school teachers. This survey informs us that: **96%** of teachers think it is important to extremely important that climate change be taught in high schools; **83%** of teachers feel that curricula on climate change is relevant to their learning objectives for students; and the **top reasons** that climate change is not taught in class is that **teachers do not have enough time to incorporate lessons and are unaware of sufficient resources.**

MIT CATE

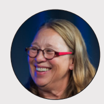
Climate Action Through Education

Managed by **Aisling O'Grady**, the team has grown to include five curriculum developers:

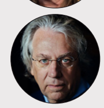
- Amy Block
- Lisa Borgatti
- Gary Smith
- Michael Kozuch
- Kathryn Teissier du Cros

MIT CATE is also supported by Northeastern co-op student Aunjoli Das and Winsor High School students Julia Bae and Anaya Raikar.

The MIT CATE Project has formed a Curriculum Review Committee to evaluate the materials and to provide feedback. The Committee is comprised of the following MIT faculty members:



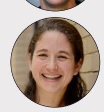
Antje Danielson
MIT Energy Initiative



Kerry Emanuel
Department of Earth, Atmospheric and Planetary Sciences

Christopher Knittel
Sloan School of Management

David McGee
Department of Earth, Atmospheric and Planetary Sciences



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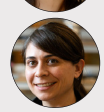

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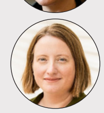

Noelle Selin
MIT Institute for Data, Systems, and Society

Want to learn more? Visit the MIT CATE page at the link below:

https://ceepr.mit.edu/cate/

Education.

An Education in Climate Change

MIT CATE Team. Pictured L to R: Aunjoli Das, Lisa Borgatti, Michael Kozuch, Gary Smith, Aisling O'Grady, Kathryn Teissier du Cros, and Christopher R. Knittel. Not Pictured: Amy Block. *Photo credit: Tony Rinaldo.*

By: Leda Zimmerman | MIT Energy Initiative

Several years ago, Christopher Knittel's father, then a math teacher, shared a mailing he had received at his high school. When he opened the packet, alarm bells went off for Knittel, who is the George P. Shultz Professor of Energy Economics at the MIT Sloan School of Management and the deputy director for policy at the MIT Energy Initiative (MITEI). "It was a slickly produced package of materials purporting to show how to teach climate change," he says. "In reality, it was a thinly veiled attempt to kindle climate change denial."

Knittel was especially concerned to learn that this package had been distributed to schools nationwide. "Many teachers in search of information on climate change might use this material because they are not in a position to judge its scientific validity," says Knittel, who is also the faculty director of the MIT Center for Energy and Environmental Policy Research (CEEPR). "I decided that MIT, which is committed to true science, was in the perfect position to develop its own climate change curriculum."

Today, Knittel is spearheading the Climate Action Through Education (CATE) program, a curriculum rolling out in pilot form this year in more than a dozen Massachusetts high schools, and eventually in high schools across the United States. To spur its broad adoption, says Knittel, the CATE curriculum features a unique suite of attributes: the creation of climate-based lessons for a range of disciplines beyond science, adherence to state-based education standards to facilitate integration into established curricula, material connecting climate change impacts to specific regions, and opportunities for students to explore climate solutions.

CATE aims to engage both students and teachers in a subject that can be overwhelming. "We will be honest about the threats posed by climate change but also give students a sense of agency that they can do something about this," says Knittel. "And for the many teachers—especially non-science teachers—starved for knowledge and background material, CATE offers resources to give them confidence to implement our curriculum."

Partnering with teachers

From the outset, CATE sought guidance and hands-on development help from educators. Project manager Aisling O'Grady surveyed teachers to learn about their experiences teaching about climate and to identify the kinds of resources they lacked. She networked with MIT's K–12 education experts and with Antje Danielson, MITEI director of education, "bouncing ideas off of them to shape the direction of our effort," she says.

O'Grady gained two critical insights from this process: "I realized that we needed practicing high school teachers as curriculum developers and that they had to represent different subject areas, because climate change is inherently interdisciplinary," she says. This echoes the philosophy behind MITEI's energy studies minor, she remarks, which includes classes from MIT's different schools. "While science helps us understand and find solutions for climate change, it touches so many other areas, from economics, policy, environmental justice and politics, to history and literature."

In line with this thinking, CATE recruited Massachusetts teachers representing key subject areas in the high school curriculum: Amy Block, a full-time math teacher, and Lisa Borgatti, a full-time science teacher, both at the Governor's Academy in Byfield; and Kathryn Teissier du Cros, a full-time language arts teacher at Newton North High School. The fourth member of this cohort, Michael Kozuch, is a full-time history teacher at Newton South High School, where he has worked for 24 years. Kozuch became engaged with environmental issues 15 years ago, introducing an elective in sustainability at Newton South. He serves on the coordinating committee for the Climate Action Network at the Massachusetts Teachers Association. He also is president of Earth Day Boston and organized Boston's 50th anniversary celebration of Earth Day. When he learned that MIT was seeking teachers to help develop a climate education curriculum, he immediately applied.

"I've heard time and again from teachers across the state that they want to incorporate climate change into the curriculum but don't know how to make it work, given lesson plans and schedules geared toward preparing students for specific tests," says Kozuch. "I knew that for a climate curriculum to succeed, it had to be part of an integrated approach."

Using climate as a lens

Over the course of a year, Kozuch and fellow educators created units that fit into their pre-existing syllabi but were woven through with relevant climate change themes. Kozuch already had some experience in this vein, describing the role of the Industrial Revolution in triggering the use of fossil fuels and the greenhouse gas emissions that resulted. For CATE, Kozuch explored additional ways of shifting focus in covering U.S. history. There are, for instance, lessons looking at westward expansion in terms of land use, expulsion of Indigenous people, and environmental justice, and at the Baby Boom period and the emergence of the environmental movement.

In English/Language Arts, there are units dedicated to explaining terms used by scientists and policymakers, such as "anthropogenic," as well as lessons devoted to climate change fiction and to student-originated sustainability projects.

The science and math classes work independently but also dovetail. For instance, there are science lessons that demystify the greenhouse effect, utilizing experiments to track fossil fuel emissions, which link to math lessons that calculate and graph the average rate of change of global carbon emissions. To make these classes even more relevant, there are labs where students compare carbon emissions in Massachusetts to those of a neighboring state, and where they determine the environmental and economic costs of plugging in electric devices in their own homes.

Throughout this curriculum-shaping process, O'Grady and the teachers sought feedback from MIT faculty from a range of disciplines, including David McGee, associate professor in the Department of Earth, Atmospheric and Planetary Sciences. With the help of CATE undergraduate researcher Heidi Li '22, the team held a focus group with the Sustainable Energy Alliance, an undergraduate student club. In spring 2022, CATE convened a professional development workshop in collaboration with the Massachusetts Teachers Association Climate Action Network, Earth Day Boston, and MIT's Office of Government and Community Relations, sponsored by the Beker Foundation, to evaluate 15 discrete CATE lessons. One of the workshop participants, Gary Smith, a teacher from St. John's Preparatory School in Danvers, Massachusetts, signed on as a volunteer science curriculum developer.

"We had a diverse pool of teachers who thought the lessons were fantastic, but among their suggestions noted that their student cohorts included new English speakers, who needed simpler language and more pictures," says O'Grady. "This was extremely useful to us, and we revised the curriculum because we want to reach students at every level of learning."

Reaching all the schools

Now, the CATE curriculum is in the hands of a cohort of Massachusetts teachers. Each of these educators will test one or more of the lessons and lab activities over the next year, checking in regularly with MIT partners to report on their classroom experiences. The CATE team is building a Climate Education Resource Network of MIT graduate students, postdocs, and research staff who can answer teachers' specific climate questions and help them find additional resources or datasets. Additionally, teachers will have the opportunity to attend two in-person cohort meetings and be paired with graduate student "climate advisors."

In spring 2023, in honor of Earth Day, O'Grady and Knittel want to bring CATE first adopters—high school teachers, students, and their families—to campus. "We envision professors giving mini lectures, youth climate groups discussing how to get involved in local actions, and our team members handing out climate change packets to students to spark conversations with their families at home," says O'Grady.

By creating a positive experience around their curriculum in these pilot schools, the CATE team hopes to promote its dissemination to many more Massachusetts schools in 2023. The team plans on enhancing lessons, offering more paths to integration in high school studies, and creating a companion resource website for teachers. Knittel wants to establish footholds in school after school, in Massachusetts and beyond.

"I plan to spend a lot of my time convincing districts and states to adopt," he says. "If one teacher tells another that the curriculum is useful, with touchpoints in different disciplines, that's how we get a foot in the door."

Knittel is not shying away from places where "climate change is a politicized topic." He hopes to team up with universities in states where there might be resistance to including such lessons in schools to develop the curriculum. Although his day job involves computing household-level carbon footprints, determining the relationship between driving behavior and the price of gasoline, and promoting wise climate policy, Knittel plans to push CATE as far as he can. "I want this curriculum to be adopted by everybody—that's my goal," he says.

"In one sense, I'm not the natural person for this job," he admits. "But I share the mission and passion of MITEI and CEEPR for decarbonizing our economy in ways that are socially equitable and efficient, and part of doing that is educating Americans about the actual costs and consequences of climate change."

The CATE program is sponsored by CEEPR, MITEI, and the MIT Vice President for Research.

This article also appeared in the Winter 2023 issue of Energy Futures, *the magazine of the MIT Energy Initiative.*

Climate Action and Education Conference

By: Aisling O'Grady

Professor Christopher R. Knittel introducing CATE and the conference.
Photo credit: Tony Rinaldo.

On April 1st, 2023 CATE hosted a conference for high school students and K–12 teachers around climate action and education at MIT's Sloan School of Management. The event was sponsored by the MIT Climate Nucleus as part of Earth Month at MIT and was in collaboration with the Massachusetts Teachers Association's Climate Action Network (MTA CAN) and Earth Day Boston, supported by MITEI. Bringing together various MIT and local climate education groups, the event was a unique and successful breeding ground for conversations between teachers and students around climate in the classroom.

The following workshops were offered:

En-ROADS Climate Solutions Simulator with Bethany Patten from the Sloan Sustainability Initiative

Attendees were introduced to the En-ROADS simulator and organized into groups representing stakeholders like clean tech, oil and gas, and activists. They then identified one policy on the simulator they would advocate for toward a goal of keeping global average surface temperature from rising more than 1.5°C. Discussions and compromise ensued in the spirit of a collaborative effort to achieve mitigation, including which policies have more or less of an impact on temperature rise. Professor Christopher R. Knittel gave an overview of the consumer impact of carbon taxes and their role in climate change.

CATE Curriculum Demonstrations with Lisa Borgatti, Kathryn Teissier du Cros, Michael Kozuch, and Gary Smith

Introducing History and English/Language Arts content spanning Sustainability Jargon, the Industrial Revolution, United Nations Sustainable Development Goals, the Baby Boom and Avoiding Doom (impacts), and a Sustainability Engagement Project. The second workshop spanned Science, Math and English/Language Arts content including Endangered Languages, Earth's Energy Budget, the Greenhouse Effect, Carbon Sequestration, Energy Use.

Massachusetts Youth Climate Coalition (MYCC): Youth Meaningfully Engaging in the Climate Movement

Members of MYCC discussed how school clubs, youth-led organizations and adult-staffed organizations across Massachusetts build relationships to advocate for intersectional Climate Justice Education, including a youth-written bill to mandate climate education in the state. Attendees brainstormed ways to overcome barriers to communities most impacted by climate change, and ways to personally engage in the movement.

Climable: Designing a Green City

Through interactive activities and discussions, attendees explored the different parts of a city and what it takes to keep a community healthy, the Earth happy, and the lights on during a storm. Topics included clean energy, the different roles in a community, and local examples. Attendees ultimately designed their own green cities.

MTA CAN: Teachers Unions and Climate Education

Two workshops covered: how En-ROADS can be used in the classroom and building the climate movement, experiences from MTA members in implementing change in schools with the support of their union and community partners, brainstorming solutions for taking action in schools.

Reflections

There were 127 in attendance including MITEI staff, the CATE team, and colleagues. Attending teachers and high school students numbered around 50 each, with teachers' disciplines showing the breadth of climate: arts, literature, history, math, mental health, science, English Language Learners, world languages, and carpentry. Their grade levels spanned preschool through college, though mostly high school, demonstrating the interest in climate education for all ages.

In addition to workshops, there were tabling opportunities for networking with MIT and local climate groups. Those represented: MIT's Environmental Solutions Initiative, MIT Beaver Works, Vegan@MIT, Mothers Out Front, Alternatives for Community and Environment, Cero Cooperative, Climable, MTA, MYCC, CATE, Earth Day Boston.

A closing survey of attendees resulted in: 74% feeling climate curricula is relevant to student learning objectives, and 55–77% wanting more info about CATE PD opportunities, our online course, curriculum launch, and student involvement. Reflections included positive feedback about En-ROADS, incorporating climate solutions into the classroom moving forward, and inspiration and excitement about youth climate activism.

Events.

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

Upcoming Conferences:

2023 EPRG & CEEPR International Energy Policy Conference

September 7-8, 2023
Brussels, Belgium
in partnership with EPRG (University of Cambridge)

Fall 2023 CEEPR Research Workshop

October 2-3, 2023
Hotel Washington
Washington, D.C.

Publications.

Recent Working Papers:

WP-2023-10
Redistribution Through Technology: Equilibrium Impacts of Mandated Efficiency in Three Electricity Markets
Matti Liski and Iivo Vehviläinen, April 2023

WP-2023-09
Advances in Power-to-Gas Technologies: Cost and Conversion Efficiency
Gunther Glenk, Philip Holler, and Stefan Reichelstein, April 2023

WP-2023-08
Impacts of Rainfall Shocks on Out-Migration in Türkiye are Mediated More by Per Capita Income than by Agricultural Output
Nathan Delacrétaz, Bruno Lanz, Amir H. Delju, Étienne Piguet, and Martine Rebetez, March 2023

WP-2023-07
The Role of State Investment Banks for Renewable Energy Technologies in OECD Countries
Paul Waidelich and Bjarne Steffen, March 2023

All listed working papers in this newsletter are available on our website at:

ceepr.mit.edu/publications/working-papers

WP-2023-06
Exploring a Suitable Business Model for Nuclear Batteries
Santiago Andrade Aparicio and John E. Parsons, March 2023

WP-2023-05
Money (Not) to Burn: Payments for Ecosystem Services to Reduce Crop Residue Burning
B. Kelsey Jack, Seema Jayachandran, Namrata Kala, and Rohini Pande, February 2023

WP-2023-04
Power Price Crisis in the EU 3.0: Proposals to Complete Long-Term Markets
Tim Schittekatte and Carlos Batlle, February 2023

RC-2023-02
Research Commentary: Calls for an Electricity Market Reform in the EU: Don't Shoot the Messenger
Tim Schittekatte and Carlos Batlle, February 2023

WP-2023-03
Accelerating Electric Vehicle Charging Investments: A Real Options Approach to Policy Design
Emil Dimanchev, Stein-Erik Fleten, Don MacKenzie, and Magnus Korpås, February 2023

RC-2023-01
Research Commentary: Economy-Wide Decarbonization Requires Fixing Retail Electricity Rates
Tim Schittekatte, Dharik Mallapragada, Paul L. Joskow, and Richard Schmalensee, January 2023

WP-2023-02
The Macroeconomic Impact of Europe's Carbon Taxes
Gilbert E. Metcalf and James H. Stock, January 2023

WP-2023-01
How Much Are Electric Vehicles Driven? Depends on the EV
Siddhi S. Doshi and Gilbert E. Metcalf, January 2023

WP-2022-019
Temperature and Cognitive Performance
Benjamin Krebs, December 2022

WP-2022-018
Natural Gas in the U.S. Southeast Power Sector under Deep Decarbonization: Modeling Technology and Policy Sensitivities
Aaron Schwartz, Jack Morris, and Dharik Mallapragada, November 2022

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Photo: Graduating CEEPR RA Alexa Canaan at the MIT Earth Day Colloquium poster session presenting research she conducted with Professor Christopher Knittel and partners at Iberdrola to Massachusetts Senator Mike Barrett. *Photo credit: Caitlin Cunningham Photography.*

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