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Editorial

Already brisk for much of the decade, the pace of change in energy and environmental policy only seems to have accelerated this year. Domestically, the administration of President Biden is rolling back decisions of the previous administration and aligning different aspects of executive action – from public procurement to oil and gas permitting on federal lands – with its 'whole of government' climate plan. President Biden has rejoined the international Paris Agreement and committed the United States to reducing greenhouse gas emissions by 50-52% below 2005 levels until 2030.

Proposals for the 2022 federal budget and an extensive infrastructure plan envision unprecedented levels of investments in low-carbon technology innovation and deployment, as legislators deliberate on details of a federal clean electricity standard to decarbonize the U.S. power system by 2035. Meanwhile, a power crisis in Texas and neighboring states caused by severe winter weather and a ransomware cyberattack on an oil pipeline system in the U.S. Southeast have revived the debate about policies to ensure the resilience of critical energy infrastructure.

A similar pace of policy developments is also visible elsewhere. Across the Atlantic, for instance, the EU is rolling out details of the European Green Deal, set to dramatically ramp up the speed of decarbonization across all sectors and redefining the parameters of sustainable finance and trade. Courts in several countries have ordered governments and private companies to accelerate their climate efforts, and shareholders of multinational oil and gas companies have voted to diversify operations and commit to carbon neutrality – including for sold products – by mid-century. Changes at this scale may be justified by climate science, but they also risk exacerbating the impacts of poor policy decisions. That is why levelheaded and fact based analysis of policy options – such as that described in this newsletter – matters more than ever. CEEPR looks forward to providing that as it accompanies the evolving policy debate.

—Michael Mehling

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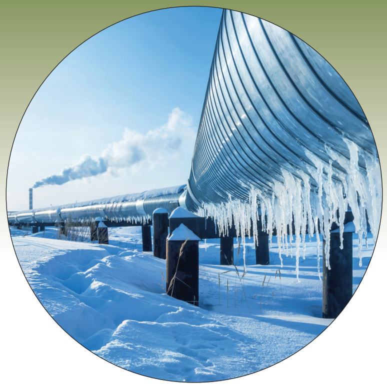

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Resilient Decarbonization for the United States: Lessons for Electric Systems from a Decade of Extreme Weather

by: Sohum Pawar

The past decade has seen an unprecedented surge of climate change-driven extreme weather events that have wrought over $800 billion in damage and taken more than 5,200 lives across the United States — a trend that appears poised to intensify.

In a new Working Paper[1], Sohum Pawar argues that the principles of resilience can play a valuable role by enabling the decarbonization of the U.S. electric system, in the face of the escalating risks and impacts of climate-driven extreme weather. His research results also offer lessons for addressing weather-induced electricity grid failures such as those recently witnessed in Texas in February 2021. The Working Paper seeks to inform present and future resilient decarbonization efforts by examining the lessons of the past decade of extreme weather, and its impact on electric systems in the United States. To do so, it considers three cases:

- Hurricane Maria, which struck Puerto Rico in 2017, causing the world's second-largest blackout;
- The 2017-2019 Northern California wildfire seasons, which sent the nation's largest investor-owned-utility into bankruptcy and remain the most devastating on record;
- Superstorm Sandy, which served as a wakeup call for the New York/New Jersey region, when it made a sudden left turn towards the region in 2012.

Pawar finds that resilient decarbonization, while a challenging process to set into motion, does in fact meet its dual mission of protecting electric systems against growing climate risks, while enabling their decarbonization. In his research, Pawar also examines the ways in which electric system institutions take climate risks into account, the strengths and weaknesses of resilience-based measures for electric systems, and overarching questions about the role of electricity and electric utilities in American society today.

Foundation: Decarbonization, Climate Risk, & Resilience

Before diving into the cases, Pawar first establishes three key pillars that form the foundation of the concept of resilient decarbonization: the need for decarbonization, the growing climate risks to the U.S. electric system, and the notion of resilience.

He first considers the need for decarbonizing the electric system. After examining the progress to date, the Working Paper highlights the estimated massive scale of infrastructure expansion that decarbonizing the U.S. electric system will require — on the order of 2 TW of generation and a more than doubling of transmission capacity.

Pawar then draws on climate data to examine the growing climate risks the U.S. faces, and the impacts those could have on a decarbonized, expanded power system. By comparing metrics of historical vulnerability to environmental risk with the geographies that will likely be major sites of electric system expansion and investment, he finds that the most vital regions are also the ones that have historically faced the greatest risk — an intuitive result of having a massive, nationwide electric system.

That means that any effort to decarbonize the U.S. electric system will require building gigawatts of new infrastructure in harm's way — regions that are known to face current and future climate change impacts. Pawar's analysis examines which impacts matter most, recognizing that extreme weather events cause the overwhelming majority of weather and climate-related damages in the U.S., and that they have accelerated in intensity at an alarming rate over the past decade, and indeed, over just the past three years.

And finally, the Working Paper identifies the principle of resilient decarbonization as a potential solution to this conundrum. To this end, Pawar highlights the potential value of resilience — a focus on the proactive, risk-informed design of systems that can gracefully fail in the face of overwhelming impacts, in order to minimize damage and facilitate an effective recovery. Pawar argues that resilience can not only help ensure that the electric system is better equipped to handle the risks of climate-driven extreme weather, but also enhance and enable its decarbonization.

Lessons from a Decade of Extreme Weather

Building on the foregoing foundation, Pawar proceeds to look back over the past decade, to see what lessons can be gleaned from three of the most devastating extreme weather events on record.

First, he considers Hurricane Maria, which blazed a path across Puerto Rico in September 2017. In its wake, Maria left 3,000 dead, completely destroying the Puerto Rican electric system and causing the second largest power outage the world has ever seen. Pawar examines how a legacy of legal loopholes, financial missteps, and the systematic second-class status accorded to U.S. territories weakened the commonwealth's institutions. He also examines the series of events that led up to the blackout, and follow the island's slow, halting recovery.

In the wake of Hurricane Maria, Pawar examines how Puerto Rico's financially crippled utility and government lacked the capacity to recover effectively from the unprecedented level of devastation wrought upon its electric system — and notes that it was the most socioeconomically vulnerable parts of the population that bore the brunt of the loss of life that resulted. However, his research also affirms the remarkable effort at realignment that PREPA and the commonwealth have made in the years since, centering their entire electric planning philosophy on the concept of resilient decarbonization, by pushing for grid isolation capabilities that can also enable the deployment of more solar generation and battery storage. But in the wake of a series of earthquakes that have struck the island this year, he notes that Puerto Rico's plans still have a long way to go.

Next, Pawar examines the 2017 and 2018 Northern California wildfire seasons, and the Camp Fire — the deadliest wildfire in California history. He begins by following the stories of the two most destructive wildfire seasons the state has ever seen, before diving into the story of the Camp Fire, and the events that precipitated it. Pawar's Working Paper considers how an increase in climate-driven wildfire risk (among other factors) has threatened – and continues to threaten – Northern California, before turning to the other key figures in these fires: the Pacific Gas and Electric Company, whose electrical equipment caused eighteen of the most destructive fires over the past three years, and the regulators charged with overseeing them. In Northern California, Pawar's research leads him to assess the role of PG&E: a utility so busy trying to juggle its past missteps and its future decarbonization efforts, that it allowed the presently growing risk of extreme, climate-driven wildfires to catch it unawares — as it did the regulator, CPUC.

Pawar examines the decades-long chain of priority whiplash that led both organizations to neglect safety and maintenance, leading to the most devastating wildfire seasons California has ever seen. In the aftermath of the Camp Fire, he examines how mounting legal liabilities under California's unique doctrine of inverse condemnation sent PG&E into bankruptcy — placing billions of dollars of renewable power purchase agreements at risk.

But from there on out, Pawar's analysis reveals a profound change in orientation. As it sought to emerge from bankruptcy, PG&E appears to have thrown itself headfirst into its Wildfire Mitigation Plan and system resilience efforts. And the state government created the Wildfire Fund, a novel financial mechanism designed to shield utilities from the runaway liabilities that brought PG&E to its knees, while still trying to maintain some modicum of accountability. In the aftermath of the relatively mild 2019 fire season, aided by PG&E's Public Safety Power Shutoffs, Pawar finds that while the utility met the test of resilience on a technical level, plunging millions of Californians into the dark, in order to avoid burning down large parts of the state, can hardly be considered true resilience.

Third, Pawar's research takes him back to 2012, when Superstorm Sandy made an unexpected left turn towards New York and New Jersey, to understand how that surprise storm has served as a remarkable catalyst for resilient decarbonization After examining the events of the storm, its impact on the two states' electrical systems, and the subsequent recovery efforts, Pawar considers the climate-driven strengthening of Atlantic hurricanes that Sandy foreshadows.

He observes how basic storm hardening measures proposed in ordinary rate cases morphed into full-fledged resilience programs, and notes the first-of-a-kind order issued by the New York PSC, which turned the old-fashioned ratemaking process into a regulatory force for resilient decarbonization. In his Working Paper, Pawar therefore previews how those investments in resilience have become the foundation of a whole new generation of multi-decadal plans for resilient decarbonization.

Lessons for Resilient Decarbonization

Looking across all three of these cases, Pawar's research identifies three major categories of lessons for resilient decarbonization: those about the risks we face, those about the role of resilience, and those that encourage us to reimagine our electric systems. He notes that climate risks and impacts can no longer be ignored, as they exacerbate a multitude of existing vulnerabilities by amplifying extreme weather events. He also examines the legal and financial risks of climate change, both as tipping points to be wary of, and as opportunities to exploit an information asymmetry in support of resilient decarbonization.

Turning to the role of resilience in electric systems, Pawar's findings lead him to conclude that it not only offers tangible protection against the growing risks of climate-driven extreme weather, but also serves to enable and catalyze decarbonization efforts. He finds that crises like devastating hurricanes and wildfires can serve as powerful vehicles for transformative change if there is sufficient institutional capacity present, but can prove overwhelming in its absence. While resilience may be a buzzword, Pawar finds that its components decidedly are not, and that neglect of essential functions like maintenance and safety has led to many of the crises examined in the Working Paper.

Admitting that resilience is far from a silver bullet for the inequities that Pawar's research has highlighted, he nevertheless contends that resilience can help cushion the blows of extreme weather events for those communities and populations that are already the most vulnerable to them. And while stopgap measures may have been accepted as a necessary tool, he cautions against letting such interim measures become locked-in.

Pawar then takes a step back, and noteds that in many cases, proposing radical, likely unrealistic proposals that challenges the status quo of an electric system can help jolt a stagnant bureaucracy or a stalled conversation, helping enable tangible progress towards resilient decarbonization.

And finally, Pawar questions the incentives that drive the generation, transmission, distribution, and sale of electricity — a commodity upon which our lives so firmly depend in this day and age — and posits that short-term financial drives are, in many cases, crowding out long-term public goals.

Lessons for resilient decarbonization

1. Climate risks and impacts are not black swans
2. Climate impacts make the bad, worse: loss amplification & compound risks
3. Legal & financial climate impacts: tipping points & potential opportunity
4. Resilience offers tangible protection against extreme weather
5. Climate resilience can enable and catalyze decarbonization efforts
6. Is a crisis a terrible thing to waste? It depends
7. Harness existing regulatory processes, but do it early
8. Resilience is a buzzword, but its most important elements are not
9. Resilience is not a silver bullet for inequality
10. Stopgap measures will likely play a role, but beware lock-in
11. Ambitiously questioning the status quo can catalyze tangible progress
12. Electric mismatch: short-term financial incentives vs. long-term public goals.

Resilient Decarbonization Challenges for a New Decade: Texas

While the Working Paper focuses on the past decade of extreme weather impacts on power systems, this new decade has already provided a fresh example of how a lack of resilience to extreme weather can cripple an electric system — and a reminder of the challenges of building that resilience in the face of an uncertain future. It seems fair to say that the historic cold wave which swept across the U.S. in mid-February of 2021 hit the Texan electric system harder than any other. By the end of it, over 4.5 million Texans served by the state's electrical grid — famously designed to minimize interconnection with the rest of the nation (and thus, federal regulation) — had been left without power for days.

While the cause of the outages are being scrutinized by state and federal regulators, as well as the Texas Legislature and U.S. Congress, a few key drivers already appear clear. Cold weather that exceeded the Texas grid operator's most extreme winter planning scenario led to an historic spike in electric-heating-driven power demand, just as record amounts of generation (primarily thermal natural gas plants, as well as coal, wind, and even nuclear units) were going out of service as instrumentation, equipment, and even the wellheads and pipes supplying them with natural gas froze up. The resulting supply/demand imbalance reportedly put the grid just "minutes" away from a total system failure that could have led to much longer outages, forcing grid operators to preemptively impose outages.

Even from just the facts that are known now, a few lessons for resilient decarbonization are clear. First, as in California, NY/NJ, and Puerto Rico, this was no black swan event. While it clearly exceeded the planning of the Texas grid, a 2011 FERC report warning of the need for winterization in the wake of another disruptive cold snap shows that this was a recognized risk.

If so, why was it not acted upon? Again, the (for now, still metaphorical) jury remains out. But a few key elements still seem evident. As the failure to weatherize appears to show, private incentives alone were not sufficient to achieve public policy aims of reliability. And policymakers' failure to mandate such efforts highlights — just as we saw in California and NY/NJ — that while regulatory processes can serve as key forcing functions for resilience, they can just as easily lag behind on urgent needs.

More broadly, the events in Texas reinforce the need for greater systemic resilience in electric systems — both as a ward against extreme weather to come, but also as a prerequisite to effective decarbonization. Electric systems like Texas's (and California's, NY/NJ's, and Puerto Rico's) have been designed, built, and operated largely based on historical assumptions. But for a whole host of reasons (climatic and otherwise) those assumptions are beginning to break down — and we must take steps to plan and respond accordingly. The Working Paper highlights the question of "a crisis wasted" — the idea that the aftermath of a disaster can serve as powerful motivation for transformative change, or send us into a defensive crouch, depending on the institutional capacity at hand. What lessons we draw from the Texas crisis remains to be seen — and remains up to us.

[1] Sohum Pawar (2021), "Resilient Decarbonization for the United States: Lessons for Electric Systems from a Decade of Extreme Weather," *CEEPR WP-2021-004*, February 2021.

Sohum Pawar

A Machine Learning Approach to Evaluating Renewable Energy Technology: An Alternative LACE Study on Solar Photo-Voltaic (PV)

by: Benny Siu Hon Ng, Christopher R. Knittel, and Caroline Uhler

Using a more holistic approach, we measure the Levelized Avoided Cost of Electricity (LACE), which considers what it will cost the grid to generate electricity using renewable technology, amortized over its lifetime, to assess the economical value of the renewable generating technology.

Within the U.S. electricity market, renewable technologies are often evaluated using the Levelized Cost of Electricity (LCOE), which is a measure of building and operating a generating plant over an assumed financial life and duty cycle. Naturally, instead of only measuring the cost, a more holistic approach would be to also assess the economic value of the renewable generating technology. In this research[1], we will use the Levelized Avoided Cost of Electricity (LACE), which considers the economic benefits of the electricity the plant brings to the grid, amortized over its lifetime, to understand the following:

1. can we better leverage Machine Learning and Optimization techniques to achieve better estimates of the value of solar technology;
2. based on these estimates, how does this compare against traditional cost estimates of alternative energy;
3. can we place an implicit value on an improvement of price prediction, particularly in the context of making better decisions during policy considerations.

To address these questions, we will implement current state of the art machine learning techniques to forecast 2016 electricity prices within the CAISO electricity market. Specifically, we will be experimenting with different variants of a recurrent neural network (RNN), which includes starting with a basic RNN, and then adding Gated Recurrent Units (GRU) and Long Short-Term Memory (LSTM) units to train a model that will return the best prediction accuracy. Part of creating this model will also involve carrying out hyperparameter tuning, using a basic grid search algorithm, to compare among different model architectures and select a final model architecture that is customized to the CAISO market and has the best prediction power. These predicted prices will be incorporated with meteorological data, such as solar radiation values, in the respective nodal locations to determine the LACE of solar technology across all the various nodes in the CAISO market.

We continue to investigate on the effects of improving the prediction power of electricity prices and its impact on respective LACE values. This will be done through understanding the underlying characteristics of the prediction errors from our machine learning model. Subsequently, we will simulate new prediction errors with various scales and analyze the respective LACE values determined.

From a policy and decision making perspective, the LCOE is currently still the leading measure when it comes to evaluating alternative sources of electricity generation. We will relate this to the LACE of respective nodes calculated and identify a breakeven cost to determine when and how decision makers can evaluate benefits of switching to solar alternatives. Finally, linking back to a machine learning view, we will estimate an implicit value of the benefits the improved prediction performance of machine learning can bring to decision makers.

Overall, a LSTM model was found to be the best model to predict hourly CAISO electricity prices with a Mean Absolute Scaled Error (MASE) of 0.761, indicating that the prediction performance outperforms a naïve baseline of using the DA price of the same hour. An in-depth analysis of the prediction errors found that they follow a normal distribution and this relationship was used to simulate 2000 'predictions' to compare the expected LACE to the respective simulated Mean Absolute Percentage Error (MAPE) rate.

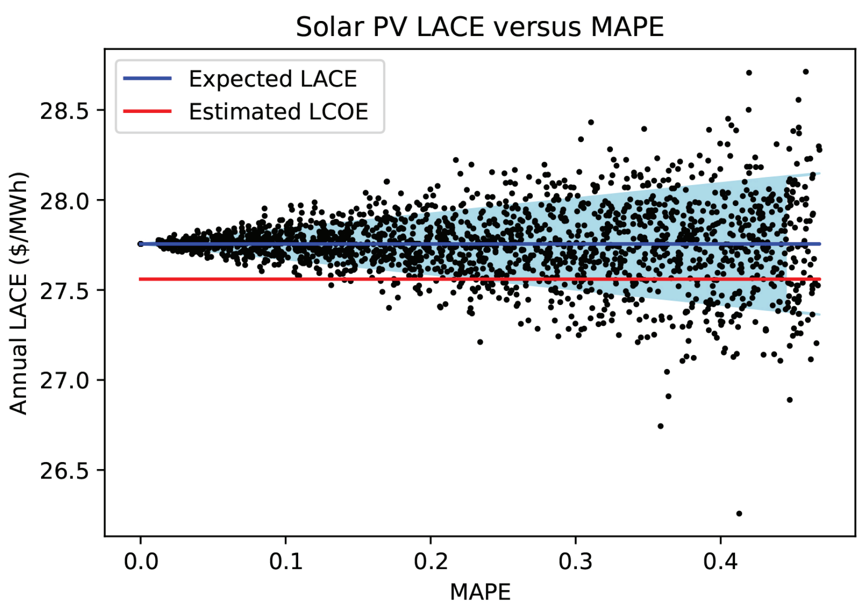


Figure: Plot of simulated LACE versus Mean Absolute Percentage Error (n = 2000) for an example node in CAISO. The blue line indicates the expected LACE based on 2016 predicted prices, the red line indicates the estimated LCOE, and the light blue area denotes the standard deviation of the simulated LACE computation.

Figure 1 to the left shows an example of simulated LACE versus MAPE with the blue line indicating the expected LACE. The breakeven point is determined when you incorporate the estimated LCOE (red line) of solar at the node, with a LACE valuation above the LCOE presenting a strong case for a switch to alternative sources of electricity generation. With reduced variability of our LACE valuation, the confidence increases of being above the breakeven point. This represents an approximate change of 1% decrease in confidence for every % increase in MAPE. Our prediction model currently reports a MAPE of about 0.25. Based on current LCOE values from EIA Annual Report 2020, when we compare this with the LACE computed from our model, only less than 0.5% of nodes in CAISO would break even at today's LCOE for solar PV.

Comparison of the LACE and LCOE metric will provide easy economic comparison, not just for solar PV but across alternative renewable sources as well. This can improve our decision making in terms of switching away from current electricity generation sources to alternatives as we work towards meeting current climate goals with larger scale implementation of renewable alternatives.

[1] Benny Siu Hon Ng, Christopher R. Knittel, and Caroline Uhler (2020), "A Machine Learning Approach to Evaluating Renewable Energy Technology: An Alternative LACE Study on Solar Photo-Voltaic (PV)", *CEEPR WP-2020-021*, MIT, December 2020.

Benny Ng

Christopher R. Knittel

Caroline Uhler

Energy Storage Investment and Operation in Efficient Electric Power Systems

by: Cristian Junge, Dharik Mallapragada, and Richard Schmalensee

In this paper, we consider welfare-optimal investment in and operation of electric power systems with constant returns to scale in multiple available generation and storage technologies under perfect foresight.

Variable renewable energy (VRE) resources, mainly wind and solar, are becoming increasingly important sources of electricity in many regions. Because the maximum output of VRE generators is variable and imperfectly predictable, however, increased penetration of VRE generation makes it more difficult for power system operators to match supply and demand at every instant. The traditional solution to this problem would be to employ more gas turbines or gas combined-cycle plants, both of which can increase and decrease output rapidly. But building more gas-fired generation is inconsistent with climate policy mandates and a desire to reduce carbon dioxide emissions.

As the costs of storage, particularly lithium-ion battery storage, have rapidly declined, storage has emerged as a potentially attractive, carbon-free alternative solution to problems posed by increased VRE penetration. Policymakers are therefore encouraging the deployment of storage. In California, for instance, the Public Utilities Commission has been requiring load-serving entities to procure storage since the promulgation of statutory requirements in 2010. Battery storage targets have also been established, inter alia, in Massachusetts, Nevada, New Jersey, New York, and Oregon, and are under consideration in other states. At the national level, the Federal Regulatory Commission has issued Order 841, which is intended to open wholesale energy markets to merchant storage providers.

In this paper[1], we explore what economic theory implies about the general properties of cost-efficient electric power systems in which storage performs energy arbitrage to help balance supply and demand. We start from a Boiteux-Turvey-style investment planning model that generally assumes constant returns to scale in generation, offering a reasonable approximation for systems without significant coal or nuclear generation. There are a number of ways that storage has been added to models of this sort, and we consider an explicitly dynamic Boiteux-Turvey-style model with perfect foresight, assuming constant returns to scale in storage as well as in generation. We simulate a deeply decarbonized "Texas-like" power system under greenfield conditions with two available storage technologies: Lithium-ion batteries and power-to-hydrogen-to-power.

Applying this analytical framework, we are able to obtain a number of general results regarding investment in and operation of storage facilities under competition. Overall, our analysis reveals the greater complexity of efficient investment in and operation of storage facilities. In general, even under an assumption of constant returns to scale, storage technologies are described by the values of seven cost and performance parameters. Like reservoir hydroelectric facilities, optimal energy storage discharge depends on expectations about future demand and supply conditions, encapsulated in the shadow value of stored energy. Unlike reservoir hydro facilities, charging energy storage facilities (including pumped hydro facilities) is a decision, not something determined by nature, and the choice of storage capacity is generally less constrained than the choice of reservoir capacity.

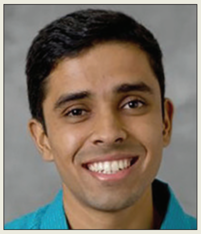
Our analysis nonetheless demonstrates that all storage technologies employed just break even at a social optimum. Since social optima and competitive equilibria coincide in the model, this break-even result provides some support for general reliance on markets to drive investments in energy storage. We also show how optimal storage operation depends on the shadow value of stored energy, though that unobservable shadow value depends on conditions in future periods. It is not possible to establish fully general results regarding investment in and operation of multiple storage technologies; there is no simple merit-order analog even under perfect foresight.

What we further demonstrate is that, if it is optimal to employ multiple storage technologies, the ones with the lowest capital cost of energy storage capacity are generally best suited to providing long-term storage. But the analysis also shows by example that storage technologies optimally play multiple roles in grid operations, providing charge-discharge cycles of various durations. Simulation of a deeply decarbonized "Texas-like" power system with two available storage technologies also shows that when multiple storage technologies are employed, frequency domain analysis is useful for characterizing the relative importance of the different cycle durations that each provides, and that these relative weights depend on the mix of generation and storage technologies employed.

Based on our results, we see three important directions for future work. First, many organized markets have capped energy prices below the true value of lost load, leading the competitive market to exhibit a "missing money" problem in which the equilibrium level of reliability provided will be too low because it will reflect the price cap rather than the true value of lost load. In such systems, subsidies to investment in storage may offer a preferable response to the missing money problem than widely used capacity mechanisms, but that has yet to be formally proven. Second, further research on frequency domain analysis is needed to examine how the power spectra of alternative storage technologies respond to changes in cost parameters and system conditions. And finally, our analysis points to a need for computational models that can be used to optimize the operation of real storage systems under realistic stochastic processes of demand and VRE generation, with realistically imperfect foresight.

[1] Cristian Junge, Dharik S. Mallapragada, and Richard Schmalensee (2021), "Energy Storage Investment and Operation in Efficient Electric Power Systems", *CEEPR WP-2021-001*, MIT, January 2021.

Cristian Junge



Dharik Mallapragada

Richard Schmalensee

Economics of Grid-Scale Energy Storage in Wholesale Electricity Markets

by: Ömer Karaduman

The transition to a low-carbon electricity system is likely to require grid-scale energy storage to smooth the variability and intermittency of renewable energy. I investigate whether private incentives for operating and investing in grid-scale energy storage are optimal and the need for policies that complement investments in renewables with encouraging energy storage.

Energy storage is the capture of energy produced at one time for use at a later time. Without adequate energy storage, maintaining an electric grid's stability requires equating electricity supply and demand at every moment. System Operators that operate deregulated electricity markets call up natural gas or oil-fired generators to balance the grid in case of short-run changes on either side. These peaker units are generally fast and flexible, but due to rapid adjustments in their heat rates, they are inefficient and emit high carbon levels. Production of Variable Renewable Energy (VRE) resources, such as wind and solar energy, exacerbates the gap between demand and supply due to their short-run variability in output. Energy storage presents a more efficient and environment-friendly alternative.

A grid-scale energy storage firm participates in the wholesale electricity market by buying and selling electricity. Energy storage creates private (profit) and social (consumer surplus, total welfare, carbon emissions) returns. Storage generates revenue by arbitraging inter-temporal electricity price differences. If storage is small, its production does not affect prices. However, when storage is large enough, it may increase prices when it buys and decreases prices when it sells. The price arbitrage transfers surplus between producers and consumers. The production of storage also shifts the production of electricity from peak periods to off-peak periods. The shift in production between generating units affects production costs and carbon emissions. Moreover, storing energy also allows increased utilization of available capacity for VRE when supply exceeds demand. Without storage, generation from these sources has to be curtailed. This research's focus[1] is also motivated by the rapidly decreasing cost of grid-scale batteries; the last decade saw a 70% reduction in lithium-ion battery packs' price.

In my model, private returns to storage are maximized by trading on intra-day price fluctuations in the wholesale electricity market. In this research, I use South Australia Electricity Market data from 2017. In the observed period, generation in South Australia consists of almost half VRE and half gas-fired generators. This generation mix is the right candidate for an economically optimal low-carbon electricity production portfolio. It also produces some of the high price variability, which creates a favorable environment for energy storage. The high penetration level of VRE also creates a considerable variation in residual demand, which helps my model to recover firms' best responses to storage's production. I evaluate hypothetical energy storage's private and social returns by estimating equilibrium strategies in the electricity market. I allow the decisions of grid-scale energy storage to affect prices.

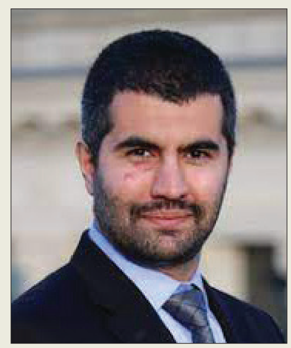
My results suggest that accounting for the equilibrium effects of storage is important for understanding the market's efficiency. This result holds even for a unit that is only 5% of the average daily capacity. This response occurs because storage activity changes thermal firms' residual demand, and therefore, their market power. In the presence of energy storage, incumbent firms bid more aggressively; in other words, energy storage helps to mitigate market power in electricity markets. Accounting for generators' best responses decreases the storage operator's profit by 10% and increases consumer welfare by 10%.

Next, I ask whether the absence of grid-scale storage is socially inefficient at current costs. Due to high investment costs, entering the electricity market is not profitable for privately operated storage and won't increase the total welfare. However, the storage-induced consumer surplus change is two times as large as the storage operator's profit, and the combined benefits are higher than the investment cost. This difference in private and social returns makes investing in storage unprofitable but socially desirable, which presents an under-investment problem. Additionally, unlike the previous literature on storage's emissions effect, I find that storage decreases emissions in markets like South Australia.

This under-investment problem suggests a public policy response, including the form of regulation that should be enacted. A hotly debated area is who should be able to own and operate storage units. I consider a load (consumer) owned energy storage. I find that it almost doubles the consumer surplus increase. This difference shows that price signals are not the right incentives to maximize social incentives because of the distortions in the market prices, such as market power.

Finally, I quantify the complementarity between VREs and grid-scale storage. I study the interaction between these technologies by assessing changes in their revenues as renewable generation is increased. At moderate levels of renewable power, when there is almost no curtailment for VREs, I find that introducing grid-scale storage to the system reduces renewable generators' revenue by decreasing average and peak prices. This is the current situation in South Australia, and below that, in most electricity systems worldwide. However, when VRE capacity is doubled from this base, storage increases the return to renewable production and decreases carbon emissions by preventing curtailment. Higher VRE capacity also leads to higher revenue for energy storage due to an increase in price variation. This non-monotonic relation between VRE and energy storage investment returns leads to a need for more carefully designed policies that complement investments in renewables with encouraging energy storage.

[1] Ömer Karaduman (2021), "Economics of Grid-Scale Energy Storage in Wholesale Electricity Markets", *CEEPR WP-2021-005*, MIT, March 2021.



Ömer Karaduman

Table 6: Storage Operator's Private and Social Returns Under Different Renewable Levels

	Per Year								
	Million AU$							Thousand Ton	Thousand MWH
	Storage's			Δ in Market's				Δ in CO_2 Emissions	Curtailment
	Revenue	Cost	Profit	Consumer Surplus	Cost	Wind Revenue	Solar PV Save		
Baseline	1.34	3.03	-1.69	3.25	-1.54	-1.70	-0.44	-3.12	-
Double Wind Capacity	2.75	3.03	-0.28	6.12	-3.12	1.63	-0.38	-8.89	-18.6
Double Solar Capacity	1.65	3.03	-1.38	4.30	-2.12	-1.43	-0.78	-4.15	-0.1

Notes: This table presents storage's simulated private and social returns under different renewable production capacities. In the baseline case, renewable capacities are at levels as they are currently seen in South Australia. In the double wind (solar) case, I double wind (solar) production by using observed renewable profiles in South Australia. In all cases, storage is a monopoly and has 120 MWh, 30 MW capacity, with 85% round-trip efficiency. The sample is from the South Australia Electricity Market July 2016 – December 2017.

Grid Impacts of Highway Electric Vehicle Charging and the Role for Mitigation by Energy Storage

by: Andrew M. Mowry and Dharik S. Mallapragada

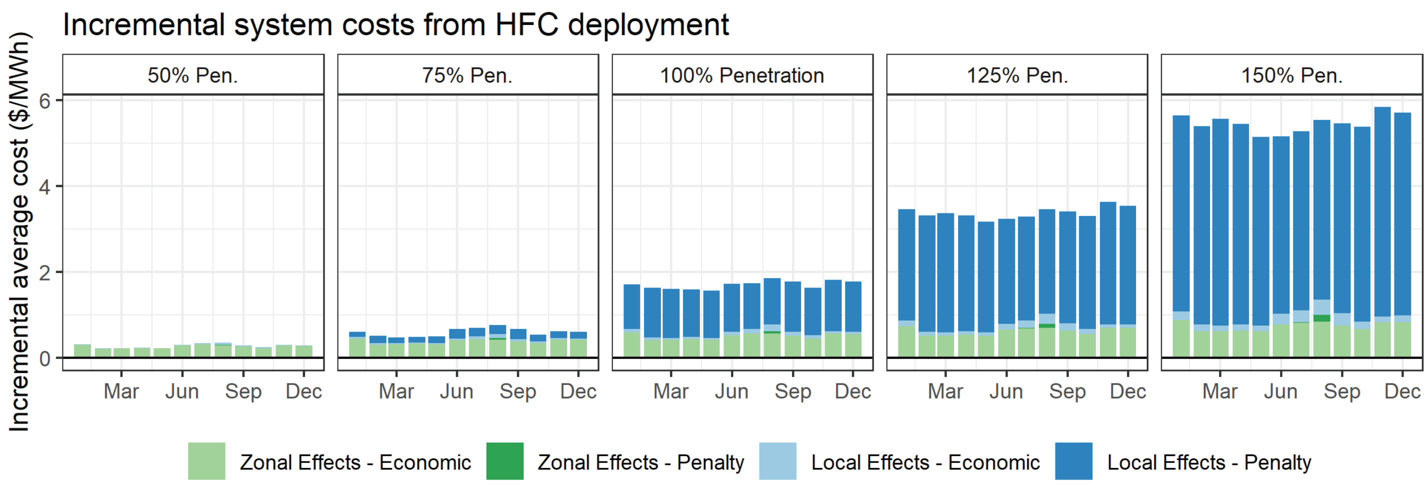


Figure: System cost impacts of HFCs. Incremental system costs of HFC infrastructure are measured as the difference in objective function value between Cases, normalized by Base Case load. The Base, Distributed, and Concentrated Cases, for various levels of EV penetration, is relative to ERCOT's LTSA forecasts for 2033. Key trends are the increasing costs withincreasing EV penetration, the presence of both Local and Zonal Effects, and non-linearity in the Local Effects.

The incoming Biden administration has positioned pro-climate infrastructure spending as the key pillar to support its ambitious economic and domestic policy goals. Already it has announced its intention to electrify the 600,000+ vehicle government-owned fleet as well as to build 500,000 new EV charging stations. The demand pull for more EVs and the anticipated monetary support for more charging stations should do much to accelerate the electrification of the American transportation sector, which contributed 28% of U.S. greenhouse gas emissions in 2018.

While vehicle electrification in the context of a low-carbon electricity generation mix will benefit air quality and mitigate climate effects, the additional electric demand from EV charging could pose challenges to the planning and operation of the electric grid. The impacts caused by workplace and home charging on distribution networks are well studied, but those caused by highway fast-charging (HFC) have not been examined in detail. The demand from these HFC stations, which are needed to alleviate "range anxiety" concerns and to enable EV travel between urban centers, is likely to be inflexible, high-powered, and spatially-concentrated. Moreover, these stations are often located in far-flung locations with weak transmission networks. Altogether, these qualities could lead HFC to have outsized costs and congestion impacts on the power grid. In this research[1] we probe this topic: what will be the impacts of large scale HFC network on the power grid? And how might they be mitigated?

To study these questions, we model a plausible HFC network and power system of Texas in 2033, when ERCOT (the Texas power grid operator) projects that 3 million passenger EVs will be on the road. We account for ERCOT's estimated renewable energy and transmission buildout between now and 2033, and we use global EV charging infrastructure statistics and the present-day Tesla Supercharger network to estimate HFC locations and peak demand in 2033. To understand the impacts of HFC on the grid, we simulate the joint charger-power system operation for a full year at detailed spatial (~3500 buses and over 9000 transmission lines) and temporal (hourly) resolution for various levels of EV penetration.

A main result is shown in the above figure, where the middle panel shows the incremental operational costs (above the case without HFC) associated with the 3 million EV base case: about $2/MWh. (For context, the marginal cost of wholesale power in the ERCOT system is usually about $20-30/MWh.)

Importantly, about 50% of these incremental costs (shown in blue) are "Local Effects" caused by congestion in the transmission system around individual stations. These effects are not visible without a fully locationally resolved ("nodal") power system model, which previous studies have not used. As EV penetration increases, these "Local Effects" begin to dominate, and thus should not be overlooked.

After identifying the system costs that HFC stations could impose on the power system, we explore mitigation methods. We first demonstrate that demand flexibility, e.g. delaying charging by one hour until power is cheaper or the system is less constrained, is not as effective as the prototypical 4-hour energy storage, like the Tesla Powerpack, at reducing these grid operational costs. (This is convenient, since it is unlikely that hurried highway travelers would want to delay their travel plans for very long.) The intuition for this result is that demand flexibility can only shift a short period of charging by about an hour, whereas a battery can shift a longer period of charging much further into the future. Taking this logic further, we qualitatively asses transmission reinforcement as a mitigation strategy: transmission can act as an "infinite duration battery" by moving energy in space rather than time. While effective, the costs and timelines for reinforcement projects are difficult to generalize beyond case studies.

By identifying the local impacts of HFC stations and moving the discussion past demand flexibility (which often is an assumed default solution to all challenges relating to power demand from EVs) we hope to stimulate the discussion of charger-grid interactions at the large scale. As automakers and governments push for electrification of the transportation sector, this analysis highlights the need for effective planning for highway EV charging infrastructure that accounts for the impacts on local power infrastructure and considers appropriate mitigation strategies.

[1] Andrew M. Mowry and Dharik S. Mallapragada (2021), "Impacts of Highway Electric Vehicle Charging and the Role for Mitigation via Energy Storage", *CEEPR WP-2021-003*, MIT, February 2021.

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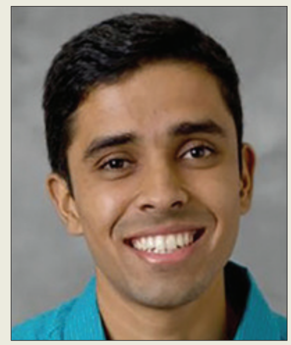


Dharik S. Mallapragada

Highway fast-charging (HFC) stations for electric vehicles (EVs) are necessary to address range anxiety concerns and thus to support economy-wide decarbonization goals through the electrification of transportation. The characteristics of HFC electricity demand – their relative inflexibility, high power requirements, and spatial concentration – have the potential to adversely impact grid operations as HFC infrastructure expands.

Trade-offs in Climate Policy: Combining Low-Carbon Standards with Modest Carbon Pricing

by: Emil G. Dimanchev and Christopher R. Knittel

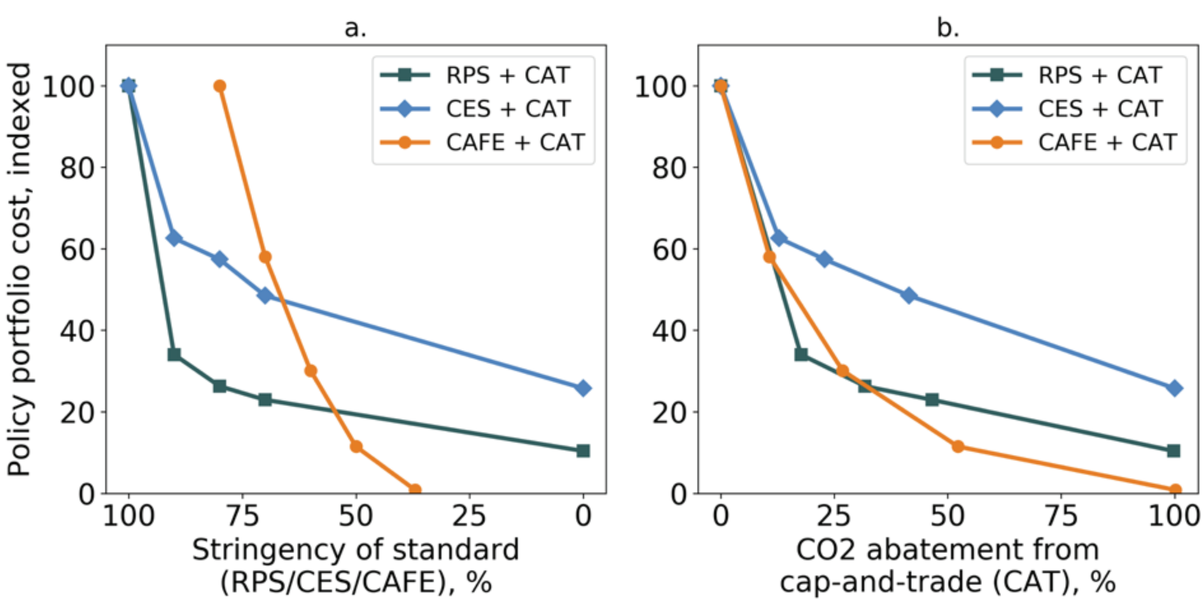
Climate policy makers have an array of policy options to choose from to meet CO_2 emission targets. The economics literature agrees that least-cost climate policy would feature carbon pricing, in the form of taxes or cap-and-trade. However, implementation efforts have shown such policies to be politically unpopular certainly at pricing levels recommended by economic theory. Political constraints may justify other, "second-best" policies from both economic efficiency and public choice theory perspectives, either because carbon pricing does not exist or because the level of the carbon price is below the efficient level. Alternative CO_2-reducing policies such as low-carbon technology subsidies and standards have seen relatively wide implementation.

Standards, which mandate a given low-carbon technology share, are a particularly common form of climate policy. Such policies are employed across U.S. states in the electricity and transportation sectors. Examples include Renewable Portfolio Standards (RPS), transportation fuel standards, and more recent zero-emission vehicle standards. At the federal level, such policies include the Corporate Average Fuel Economy (CAFE) standard and the Renewable Fuel Standard. Recently, Clean Energy Standards (CES) have come to occupy a central position in U.S. Congressional debates about future climate policy
.

While standards have political feasibility advantages relative to carbon pricing, they have been shown to be less economically efficient and to impose higher economic costs on low-income households. Therefore, the choice between carbon pricing and standards involves a trade-off between the relative efficiency and progressivity of carbon pricing on the one hand and the assumed political acceptability advantages of standards on the other.

A balance between these competing considerations may be achieved through a certain combination of both carbon pricing and standards. Most previous research has compared carbon pricing and standards in isolation, comparing the efficiency of a climate policy exclusively comprising one type of policy to a climate policy exclusively comprising the other type. Some research has included scenarios featuring a combination of carbon pricing and other policies. However, such studies have only considered a single pre-defined combination of these policies. Past research therefore does not sufficiently inform how policy makers can choose between different combinations of climate policies.

In this paper[1], we compare different combinations of standards and carbon pricing. We frame climate policy making as a choice among alternative policy portfolios that reduce the same amount



Each line represents a different kind of policy portfolio. For example, the dark blue line represents and RPS combined with a cap-and-trade (CAT), while the light blue line represents combinations of CES and CAT. The horizontal axes represent the extent to which the policy portfolio relies on the standard or cap-and-trade. Values to the left denote a higher reliance on the standard and values to the right show a higher reliance on the cap-and-trade. In panel "a." reliance is defined by the stringency of the standard. In panel "b." it is defined by the amount of abatement caused by the cap-and-trade policy (as opposed to the standard).

Climate policy makers face a wide array of policy options. Past research suggests that choosing between these low-carbon standards and carbon pricing involves trade-offs between the relative efficiency and progressivity of carbon pricing on the one hand and the political acceptability of standards on the other. We argue that a climate policy portfolio that combines both approaches may balance the distinct advantages of each.

of CO_2 but differ with respect to how much they rely on standards or carbon pricing. The extent to which a policy portfolio "relies" on a given policy is defined in multiple ways including: the stringency of the standard, and the share of abatement caused by each policy.

A climate policy portfolio that includes carbon pricing, in addition to a standard, is expected to cost less than a pure standard-based climate policy, as found in previous literature. We define this decrease in policy cost (or increase in welfare) as the efficiency benefit of carbon pricing. To inform the choice of a policy portfolio, we explore how this efficiency benefit varies as the policy portfolio relies more or less on each policy. In other words, we investigate the marginal benefit of carbon pricing across different policy portfolios.

We approach these questions through both theory and modeling. For the latter we use two previously published models: EPPA and GenX. We run these models through a novel experimental procedure, which allows us to quantify and compare the costs of different policy portfolios.

Our modeling covers a range of policy contexts. In EPPA, we explore different combinations of economy-wide carbon pricing and three different types of low-carbon standards: an RPS, a CES, and a CAFE standard. In GenX, we model an RPS combined with power sector carbon pricing, and an RPS combined with economy-wide carbon pricing.

Our results from the EPPA model (shown below) illustrate our two general findings. First, a combination of a standard and carbon pricing costs less than a standard-only policy that reduces the same amount of CO_2. This result reflects the cost-saving (i.e. efficiency) benefit of carbon pricing. Second, the cost-saving benefit of incorporating carbon pricing is large at first and diminishes the more a policy relies on carbon pricing as opposed to a standard. These two results are consistent with our modeling in GenX and the findings of our theoretical model.

This paper therefore suggests that lawmakers can drastically reduce policy costs if they combine low-carbon standards with modest carbon pricing, relative to the cost of relying on standards alone. These findings are particularly relevant for the design of standard-based climate policy packages, exemplified by recent national proposals.

More generally, we find potential advantages in hybrid policy portfolios that combine alternative policy tools, such as standards and carbon pricing. Policy debates have been previously framed as a choice between such options. We reconceptualize the problem as one of choice from different combinations of policy options. Envisioning alternative policy tools in concert, as we do in this paper, may provide a way to balance diverse societal criteria as well as an opportunity for consensus between advocates of either approach.

[1] Emil G. Dimanchev and Christopher R. Knittel, (2020), "Trade-offs in Climate Policy: Combining Low-Carbon Standards with Modest Carbon Pricing", *CEEPR WP-2020-020*, MIT, November 2020.

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MIT CEEPR Research on Carbon Pricing Cited in Congressional Hearing

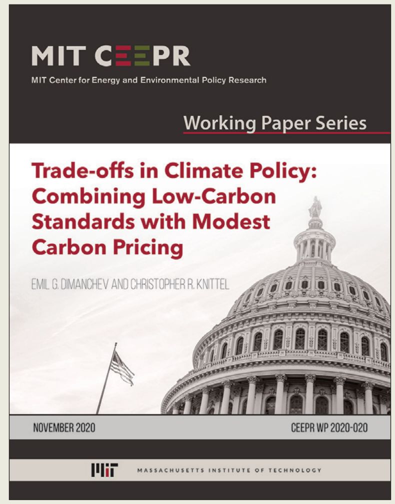
by: Michael Mehling

Congressman Scott Peters (CA-52-D) highlights a CEEPR study on the benefits of including carbon pricing in a climate policy portfolio during a U.S. House of Representatives subcommittee hearing.

Speaking at a May 19 hearing of the Subcommittee on Energy of the Committee on Energy and Commerce, Congressman Scott H. Peters referenced a Working Paper authored by MIT CEEPR Research Affiliate Emil G. Dimanchev and Faculty Director Christopher R. Knittel (see pp. 14-15 of this Newsletter).

In an exchange with U.S. Secretary of Energy Jennifer Granholm, Peters highlighted a central message of the MIT CEEPR study, which found that inclusion of a carbon price can meaningfully lower the cost of implementing a climate policy portfolio. "Even a modest carbon price is essential to reduce the cost of decarbonization, generate billions in new revenue, and drive fuel switching to zero-carbon alternatives", Peters concluded. He also suggested that inclusion of a carbon price could reduce the cost of implementing the American Jobs Plan proposed by the Administration of President Biden.

"Researchers at MIT found that a climate package that includes a modest carbon price cuts costs in half compared to a package that lacks a carbon price," he explained. Peters went on to reference the experience in his home state California, which has relied on a combination of a carbon price and more targeted policies to achieve its ambitious policy objectives.



The MIT CEEPR Working Paper WP-2020-020, "Trade-offs in Climate Policy: Combining Low-Carbon Standards with Modest Carbon Pricing", was jointly authored by Emil G. Dimanchev and Christopher R. Knittel, and published in November 2020. It can be downloaded here:

http://ceepr.mit.edu/publications/working-papers/747

A recording of the May 19 hearing on the fiscal year 2022 budget of the Department of Energy can be accessed here: https://energycommerce.house.gov/committee-activity/hearings/hearing-on-the-fiscal-year-2022-doe-budget

Q&A: Clare Balboni on Environmental Economics

by: School of Humanities, Arts, and Social Sciences Communications

In an ongoing series, Solving Climate: Humanistic Perspectives from MIT, faculty, students, and alumni in the Institute's humanistic fields share scholarship and insights that are significant for solving climate change and mitigating its myriad social and ecological impacts. In this Q&A with MIT SHASS Communications, Clare Balboni describes the burgeoning influence of economics in understanding climate, energy, and environmental issues, as well as informing related policy.

Clare Balboni is the 3M Career Development Assistant Professor of Environmental Economics at MIT and an affiliate of MIT's Center for Energy and Environmental Policy Research. Her research centers on environmental economics, trade, and development economics.

Q: In what ways are the research, insights, and perspectives from economics significant for addressing global change and its myriad ecological and social impacts?

A: There is tremendous and growing interest in environmental questions within economics. Economic models and methods can help to enhance our understanding of how to balance the imperative for continued growth in prosperity and well-being — particularly for the world's poorest — with the need to mitigate and adapt to the environmental externalities that this growth creates.

Environmental economists have taken advantage of economic tools and methodologies, and the rapid proliferation of new data sources, to study how local pollutants and greenhouse gas emissions affect a huge range of outcomes spanning such areas as mortality, health, agriculture, labor productivity, income, migration, education, crime, and conflict. Building a strong evidence base on the consequences of environmental quality, and developing techniques for measuring environmental benefits and harms, is key in informing the design of emissions reduction policies.

Another important contribution of economics is to provide robust analysis of policies that aim to tackle environmental externalities through, for instance, taxation, tradable emissions permits, regulation, and innovation policy. Recent work provides rigorous empirical evidence evaluating key environmental policies and considering important aspects of the design of economic instruments; this work builds on a longstanding body of literature within economics studying environmental policy instruments.

A growing body of empirical work in environmental economics focuses on particular issues relating to environmental quality and instrument design in developing countries, where energy use is increasing rapidly; political economy considerations may raise distinct challenges; and where both local pollutant concentrations and projected climate damages are often particularly acute.

Q: When you confront an issue as formidable as climate change, what gives you hope?

A: I draw hope from the rapidly increasing focus and attention on environmental questions across fields in economics, across disciplines in the social and natural sciences, and more broadly in the academic, policy, and popular discourse. Given the scale and breadth of the challenge, it is crucial that this combined focus from a range of perspectives continues to advance this important agenda.

Series editor and designer: Emily Hiestand
Co-editor: Kathryn O'Neill

On the Path to an Equitable Energy Transition, a New Collaborative Report Provides Insight on How to Get There

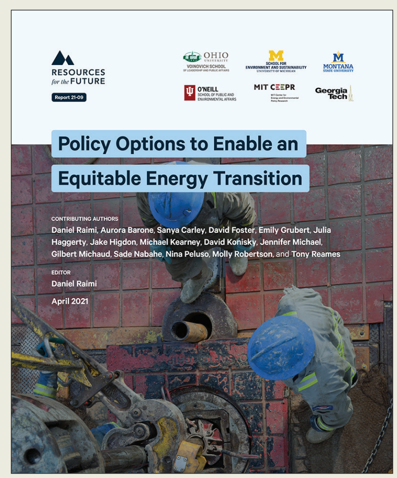
As the United States undergoes an unprecedented shift away from carbon-intensive energy sources and towards a clean energy future, federal policy will play a major role in supporting workers and regions that are affected, including low-income, rural, and minority communities.

Researchers at MIT CEEPR and the Roosevelt Project have contributed to a new collaborative report led by Washington, DC-based think tank Resources for the Future that analyzes a "menu" of 35 policy options to help workers and communities adapt in the energy transition. In light of the Biden administration's recent pledge to cut U.S. emissions by 50–52% of 2005 levels, this report lays out the costs and benefits of policies that can reduce emissions while promoting fairness for communities affected by the transition to clean energy.

A team of 15 scholars from universities across the United States worked together to analyze policy options that touch on several categories: energy infrastructure and resilience, environmental remediation, economic development, workforce, and manufacturing and innovation. Each researcher identified specific proposals and drew from available evidence to assess policy design and estimate outcomes, including effects on the environment, economy, and employment. Many of the proposals analyzed in this report are currently under consideration in Congress, and the report's authors have identified relevant pieces of legislation and sections of the U.S. Code.

Policymakers in the United States and around the world will make decisions in the coming years about how best to implement fair policies as the energy landscape changes. Although there is no "silver bullet" solution to an equitable energy transition, this report seeks to provide broad insight on the best path forward.

For more, read the report, ***Policy Options to Enable an Equitable Energy Transition***. MIT's David Foster, Michael Kearney, Sade Nabahe, and Nina Peluso contributed to the report. Daniel Raimi of Resources for the Future served as editor of the report.



This collaborative report with Resources for the Future can be found here:

http://ceepr.mit.edu/publications/working-papers/755

To learn more about the Roosevelt Project work on an equitable energy transition, please visit the project website here:

http://ceepr.mit.edu/roosevelt-project

Spring 2021 Webinars

February 10, 2021
Social Dimensions of the Energy Transition

- Stephen Ansolabehere (Harvard)
- Amy Glasmeier (MIT)

March 10, 2021
Valuing Energy Storage

- Ömer Karaduman (Stanford)
- Richard Schmalensee (MIT)

March 24, 2021
Climate Policy under the Biden Administration: A Panel Discussion

- George David Banks (Bipartisan Policy Center)
- Ana Unruh Cohen (US House Select Committee on the Climate Crisis)
- Richard Schmalensee (MIT)

April 14, 2021
Electric Mobility: Implications for Energy and the Environment

- Fiona Burlig (University of Chicago)
- Stephen Holland (UNC, Greensboro)

April 28, 2021
Decarbonizing Heat in Buildings

- Mathilde Fajardy (University of Cambridge)
- Christoph Reinhart (MIT)

May 19, 2021
Scaling Infrastructure for the Energy Transition

- Patrick Brown (NREL)
- Stephen Jarvis (University of Mannheim)

June 2, 2021
Spring 2021 CEEPR Virtual Associates Meeting

Recent Working Papers

WP-2021-006
Are "Complementary Policies" Substitutes? Evidence from R&D Subsidies in the UK
Jacquelyn Pless, April 2021

WP-2021-005
Economics of Grid-Scale Energy Storage in Wholesale Electricity Markets
Ömer Karaduman, March 2021

WP-2021-004
Resilient Decarbonization for the United States: Lessons for Electric Systems from a Decade of Extreme Weather
Sohum Pawar, February 2021

WP-2021-003
Grid Impacts of Highway Electric Vehicle Charging and the Role for Mitigation via Energy Storage
Andrew M. Mowry and Dharik S. Mallapragada, February 2021

WP-2021-002
Learning from Supply Shocks in the Energy Market: Evidence from Local and Global Impacts of the Shale Revolution
Bora Ozaltun, January 2021

WP-2021-001
Energy Storage Investment and Operation in Efficient Electric Power Systems
Cristian Junge, Dharik S. Mallapragada, and Richard Schmalensee, January 2021

WP-2020-021
A Machine Learning Approach to Evaluating Renewable Energy Technology: An Alternative LACE Study on Solar Photo-Voltaic (PV)
Benny Siu Hon Ng, Christopher R. Knittel, and Caroline Uhler, December 2020

WP-2020-020
Trade-offs in Climate Policy: Combining Low-Carbon Standards with Modest Carbon Pricing
Emil G. Dimanchev and Christopher R. Knittel, November 2020

Roosevelt Project

WP-2021-R1
Policy Options to Enable an Equitable Energy Transition
Daniel Raimi, Aurora Barone, Sanya Carley, David Foster, Emily Grubert, Julia Haggerty, Jake Higdon, Michael Kearney, David Konisky, Jennifer Michael, Gilbert Michaud, Sade Nabahe, Nina Peluso, Molly Robertson, and Tony Reames, April 2021

All listed and referenced working papers in this newsletter are available on our website at ceepr.mit.edu/publications/working-papers

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