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MIT Center for Energy and Environmental Policy Research

Newsletter

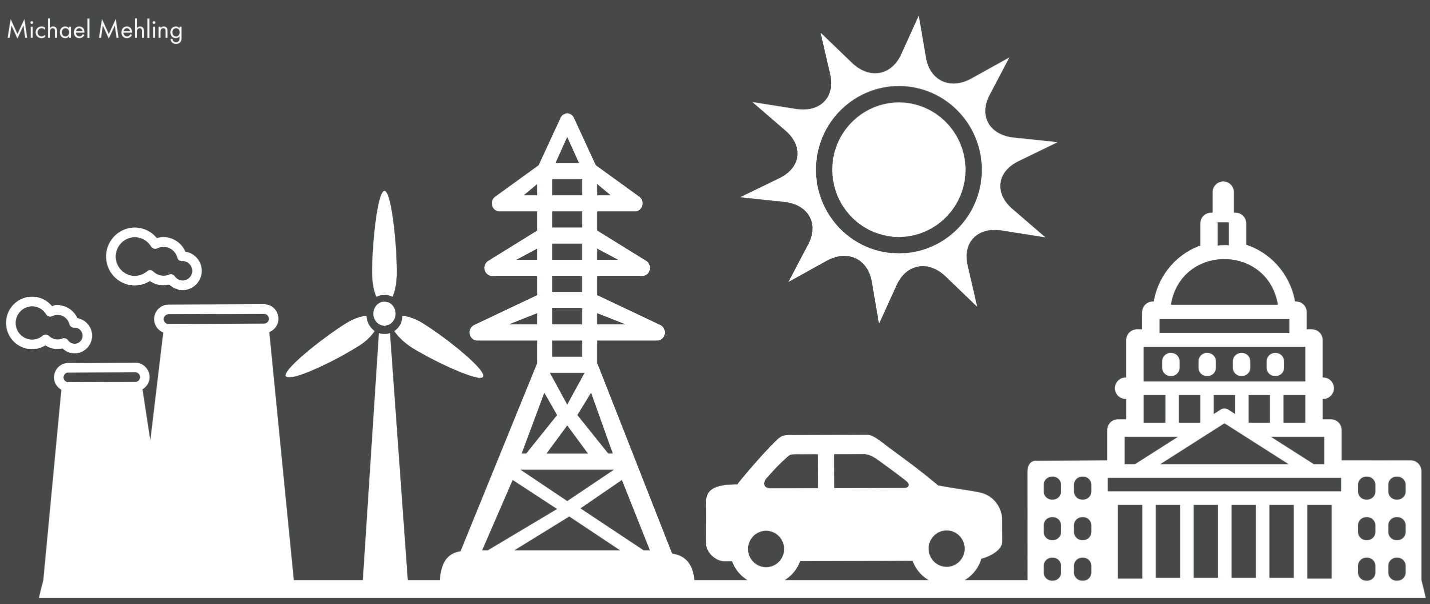
AUTUMN 2023

Editorial.

For several consecutive newsletter issues, this editorial has reflected on continuous turmoil in energy markets. Precipitated by the COVID-19 pandemic and its impact on energy demand, an initial downturn reversed course as economic recovery measures took effect and culminated in a pronounced energy crisis in those regions most affected by the Russian invasion of Ukraine. Meanwhile, dramatic legislative and policy developments on both sides of the Atlantic, themselves responding to growing public concern about the climate crisis and rising energy costs, have fundamentally altered the economic context for key areas of the energy sector and their social license to operate. Those same policy developments even prompted a brief flurry of diplomatic tensions between the United States and its European allies, as generous subsidies stood to attract rising levels of clean technology investment to North America. Following on this extended period of turbulence, the brief months since our last newsletter have offered what may seem a rare respite and return to relative normalcy in the energy arena. Energy prices have returned closer to their historical range, transatlantic frictions have abated as both regions explore cooperative solutions, and key policies have progressed from the vicissitudes of political debate to the day-to-day process of routine implementation.

This apparent respite may prove to be short lived, however. Geopolitical deadlock between the United States and China, in particular, continues to simmer and risks escalating at a moment's notice, threatening renewed supply chain disruptions, shortages of critical components and materials, and an overall increase in the cost of decarbonization. In both North America and Europe, important elections loom on the horizon, with the potential to derail the pace and scale of the ongoing energy transition as its economic impacts inflict a growing toll on households and the communities sustained by conventional energy activities. Inflationary pressures, elevated interest rates, and a growing fiscal imbalance could upend more than a decade of favorable conditions for investment in energy projects, while the soft costs of slow permitting decisions are increasingly emerging as the potentially greatest obstacle to rapid energy sector decarbonization. Readers of this newsletter issue will find these challenges variously addressed in the research currently underway at MIT CEEPR, along with several exciting announcements about new colleagues and the projects they are working on. We look forward to introducing these at our upcoming workshops, and hope to welcome you there or on our campus soon.

Michael Mehling



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Contents.

Research.

Climate Impacts of Bitcoin Mining in the U.S.

By: Christian Stoll, Lena Klaaßen, Ulrich Gallersdörfer, and Alexander Neumüller

Bitcoin mining is renowned for its energy intensity. As of March 25th, 2023, Bitcoin miners' power demand amounts to 15.4 gigawatts (GW). In the Bitcoin network, so-called miners compete in a computational puzzle to add blocks to the chain and validate coin ownership and transactions included in the blocks. To participate in the process, miners use specialized hardware devices which consume electricity.

And while scholars and Bitcoin proponents agree that miners consume vast amounts of electricity, opinions regarding the climate impacts of Bitcoin mining deviate fundamentally. Critics view Bitcoin's electricity consumption as a calamity, while proponents perceive it as a feature rather than a bug. A growing body of academic studies compares Bitcoin's carbon footprint to the emission levels of mid-sized countries. Concurrently, Bitcoin proponents highlight potential climate benefits from grid balancing services, methane emissions reductions via flare gas utilization or sealing of orphaned wells, support of renewable energy expansion, and the use of waste heat from mining hardware for ancillary activities.

We validate arguments from both sides and provide empirical evidence for the extent and energy sources of Bitcoin mining in the U.S., based on data from 13 publicly listed mining companies that account for one-fourth of the total network hashrate as of the end of 2022. Notably, during the winter storm Elliott in North America in December 2022, Bitcoin miners curtailed as much as 100 Exahashes per second (EH/s)—equivalent to 38% of the total Bitcoin network hashrate on that day. This number provides empirical evidence that at least 38% of all Bitcoin mining activity was located in the U.S. and Canada by December 2022.

We find that the carbon intensity of electricity consumed by publicly listed Bitcoin mining companies in the U.S. of 397 grams of carbon dioxide per kilowatt-hour (gCO_2/kWh) is on par with the U.S. grid average. Furthermore, we find that the annual emissions of 7.2 $MtCO_2$ caused by the 13 analyzed publicly listed miners in the U.S. alone surpass the carbon emissions of the State of Vermont. These findings, based on grid average emission factors, stand in contrast to industry claims that the majority (58.9%) of Bitcoin mining is fueled by sustainable energy as the share of non-fossil electricity from renewables (21.5%) and nuclear (18.2%) in the U.S. generation mix is significantly lower. At the same time, we find that the potential climate benefits of Bitcoin mining also warrant closer attention.

Bitcoin proponents argue that Bitcoin mining can contribute to grid stability and resilience by providing grid operators with a resource that can rapidly adjust its power usage. ERCOT, the grid operator in Texas, established a curtailment program for large flexible load (LFL) in 2022. So far, nearly the entire operational LFL can be attributed to Bitcoin mining facilities. Therefore, the LFL demand response during winter storm Elliott of 1.4 gigawatts (GW) provides a lower bound of the Bitcoin mining load in Texas as it includes only miners that qualify for the program. The 1.4 GW corresponds to 15% of the total Bitcoin network power demand on that day. However, the climate benefits arising from demand response capacity and other grid-balancing services that U.S. Bitcoin miners may provide are difficult to measure. Further research is needed to assess and compare the carbon emissions and total power system costs in scenarios with and without Bitcoin.

A second climate benefit often emphasized by Bitcoin proponents is its potential to mitigate methane emissions. Natural gas, if a by-product of oil extraction, is often uneconomical for oil producers to utilize or transport due to costly and lacking infrastructure. Consequently, producers either vent or flare the gas on site. Venting emits methane (CH_4) directly into the atmosphere—a greenhouse gas with a Global Warming Potential over a 100-year timeframe 28–36 times greater than CO_2. Insufficient electricity demand and high investment costs often render flare gas utilization projects unfeasible. Bitcoin mining may incentivize generator construction to convert the otherwise squandered energy into productive use. Furthermore, as of 2020, according to EPA research, the U.S. had 3,700,000 abandoned wells, of which 59% were unplugged, emitting 6.9 million tonnes of CO_2 equivalent ($MtCO_2e$) annually. The financial incentives of the Bitcoin network to utilize the CH_4 could subsidize the sealing of these wells. Critics, however, argue that this practice does not address the underlying issue of ongoing fossil fuel consumption and its environmental repercussions and may even inadvertently prolong fossil fuel dependency.

A third argument emphasized by Bitcoin proponents is that Bitcoin mining may facilitate the expansion of renewable energy resources. Mining in remote locations could potentially address challenges associated with integrating an increasing amount of intermittent renewable energy sources into power grids, such as the need for transmission capacity, energy storage capacity, or a lack of nearby power demand. However, quantifying the climate benefits associated with Bitcoin mining in this context is challenging, as there is no

Christian Stoll, Lena Klaaßen, Ulrich Gallersdörfer, and Alexander Neumüller (2023), "Climate Impacts of Bitcoin Mining in the U.S.", CEEPR WP-2023-11, MIT, June 2023.

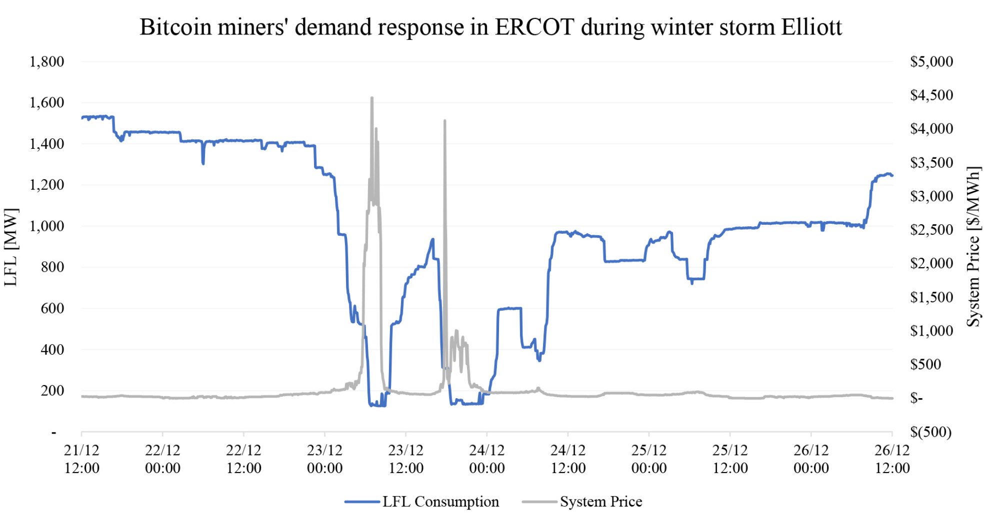


Figure 1. Large flexible load (LFL) curtailment during winter storm Elliott according to ERCOT data.

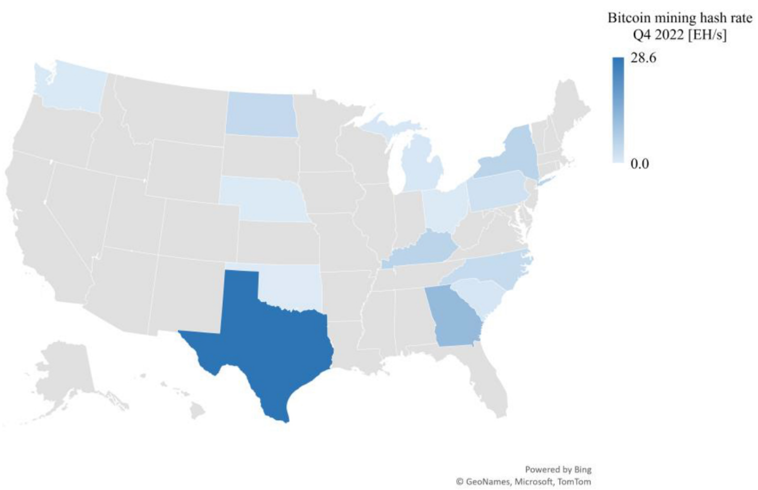
comprehensive record of Bitcoin miners who invested in installing additional renewable energy resources.

Another argument brought forth by advocates of Bitcoin concerns the utilization of heat generated by Bitcoin mining operations. Bitcoin miners may have a financial incentive to capture and reutilize the waste heat, thereby reducing energy consumption elsewhere. Suggested co-locations encompass numerous applications, including greenhouses, residential buildings, water systems, swimming pools, food and wood drying, and alcohol distilleries. It is important to note, however, that the practical implementation of waste heat utilization from Bitcoin mining facilities seems limited to pilot projects.

To bridge the gap in this bifurcated debate, it is crucial to comprehend established carbon accounting rules and ascertain the data required to substantiate renewable energy claims. Although mandatory disclosure obligations for publicly listed Bitcoin miners provide valuable information regarding operational scale and geographical distribution, crucial details, such as the energy mix, often remain inadequately disclosed. The growing transparency on locations and energy sources of large publicly listed Bitcoin miners highlights the value of disclosure obligations and may help dismantle unsupported industry claims, improve assumption-based academic models, and point regulators to areas where Bitcoin mining may bring climate co-benefits. Essentially, we argue that further transparency is vital to educate Bitcoin users and inform the public, regulators, and policymakers about the climate impacts of Bitcoin mining.

—Summary contributions by Henry Kirkman

U.S. Bitcoin mining hash rate distribution



State	Number of mining facilities	Hash rate Q4 2022 [EH/s]
Texas	17	28.6
Georgia	6	11.9
New York	5	5.7
Kentucky	1	5.6
North Dakota	3	4.2
North Carolina	1	3.9
Pennsylvania	3	2.3
South Carolina	1	1.2
Michigan	1	1.1
Washington	1	0.6
Nebraska	1	0.3
Ohio	1	0.3
Oklahoma	1	0.0
Total	**42**	**65.5**

	Computing power		Power load		Carbon intensity/emissions	
Bitcoin miner	**Q4 2022* [EH/s]**	**Expansion plans [EH/s]**	**Q4 2022* [MW]**	**Expansion plans [MW]**	**Grid emission factor [gCO2/kWh]**	**Total emissions [ktCO2]**
Core Scientific	22.5	31.0	606	1,000	494	**2,620**
Riot	9.7	12.5	300	387	388	**1,021**
Marathon	7.0	23.0	245	805	416	**893**
Cipher Mining	5.2	8.2	173	267	388	**589**
CleanSpark	6.2	16.0	198	510	309	**535**
New Hut	3.1	-	135	-	365	**432**
Stronghold	2.3	3.0	105	138	330	**304**
Argo Blockchain	2.4	4.1	82	140	388	**279**
Greenidge	2.4	-	76	-	232	**154**
BitNile	1.1	2.7	36	91	455	**144**
Bit Digital	1.2	-	40	-	328	**116**
TeraWulf	1.9	5.5	50	150	207	**90**
Bitfarms	0.6	-	20	-	92	**16**
Total	**65.5**	**106.0**	**2,067**	**3,487**	**397**	**7,194**

*Or latest available data

Figure 2. Locations of mining facilities and carbon emissions of mining operations of publicly listed mining companies in the U.S.

With 17 facilities and a computing power of 28.6 Exahashes per second [EH/s], almost half of the U.S. activities of publicly listed miners are located in Texas. The combined hashrate of publicly listed miners in the U.S. of 65.5 EH/s represents 24% of the total Bitcoin network computing power as of December 31, 2022. It is noteworthy that one company alone—Core Scientific—provides 22.5 EH/s via facilities with 606 MW rated power and that all miners have communicated plans to expand their facilities.

Research.

Cost-Efficient Pathways to Decarbonize Portland Cement Production

By: Gunther Glenk, Anton Kelnhofer, Rebecca Meier, and Stefan Reichelstein

In the discussion surrounding the timely transition to a net-zero economy, commentators frequently point to the obstacles of reducing the carbon dioxide (CO_2) emissions in hard-to-decarbonize industries, such as steel, cement, and chemicals. These industries deliver products that are essential to a modern economy, yet a major share of their emissions are intrinsic process emissions that will not be avoided by phasing out the use of fossil fuels. By itself, the cement industry, in particular, is responsible for about 8% of global annual CO_2 emissions. Like their counterparts in other heavy manufacturing industries, major cement producers have recently embraced net-zero emission goals by the year 2050. The achievement of these goals will require the adoption of abatement levers that drastically reduce the emissions associated with current production processes.

This paper first develops a generic economic framework for identifying cost-efficient combinations of abatement levers a firm would need to implement to achieve substantial emission reductions. We then calibrate our model to new industry data in the context of European cement plants. Our numerical analysis considers nine elementary abatement levers that are technologically ready for deployment (see Figure 1). They include process improvements, input substitutions, such as the use of supplementary cementitious materials (SCMs), and the installation of carbon capture technologies. Since most of these elementary levers can be combined freely, there are potentially up to $2^9 = 512$ combined abatement levers. Importantly, the resulting abatement and cost analysis is not separable across the constituent elementary levers. For instance, the abatement impact of SCMs varies depending on whether the use of these materials is combined with a carbon capture installation.

The central economic concept introduced in this paper is the Incremental Abatement Cost curve. Conceptualized as the life-cycle cost of reducing emissions incrementally by certain target levels, this cost curve is a variant of the Marginal Abatement Cost curve, as popularized by McKinsey and studied in numerous contexts. A central assumption of

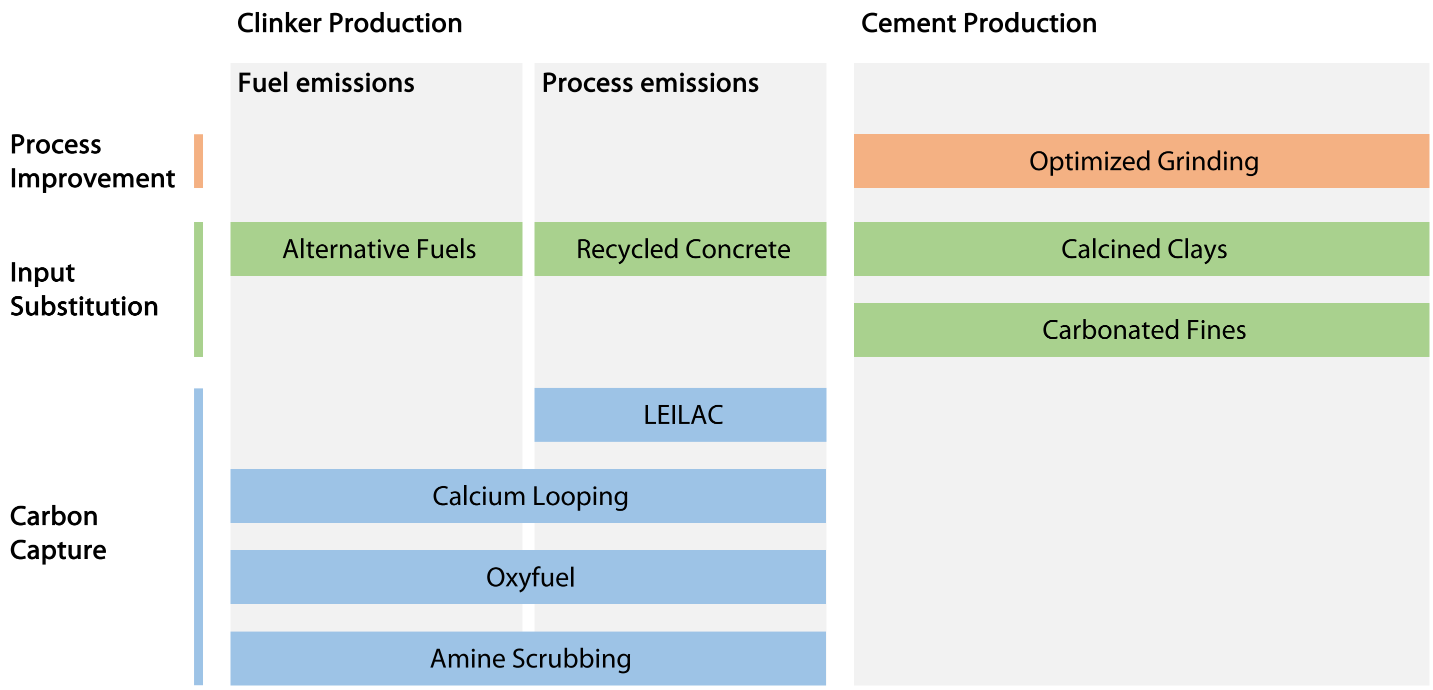


Figure 1. Elementary abatement levers. This figure illustrates the nine elementary abatement levers considered in our calculations.

marginal abatement cost curves is that the abatement impact of different levers is separable, allowing for levers to be ordered according to their marginal costs. In contrast, incremental abatement cost curves are generally not monotonically increasing in the level of abatement, precisely because the joint costs and emission levels corresponding to different combined levers are not separable across the constituent elementary levers.

Our numerical analysis examines the willingness of European cement producers to adopt combinations of elementary abatement levers in response to alternative carbon prices that might prevail under the European Emission Trading System. We find that if prices were to continue at their 2022 average value of €81 per ton of CO_2 in future years, firms would have incentives to abate their annual direct (Scope 1) CO_2 emissions by 34% relative to the status quo (see Figure 2). At the same time, our analysis demonstrates that optimal abatement levels are highly sensitive to carbon prices in the range of €80–150 per ton. Specifically, cement producers would optimally reduce their emissions by 78% at a carbon price of €100 per ton of CO_2, while €155 per ton would provide incentives sufficient for near-full decarbonization.

Our findings are generally more favorable than those reported in earlier studies regarding the cost of decarbonizing cement production. These differences partly reflect that our calculations are based on new industry data showing advances in the cost and emission profiles of different abatement technologies. Our more favorable results also reflect that our cost calculations rely on an embedded optimization algorithm that selects for each abatement target the unique cost-efficient combined lever from a large set of elementary levers.

Current climate policy discussions have yet to arrive at a consensus on how far carbon pricing regulations or subsidies for decarbonization efforts need to be expanded in order to ensure a timely transition to a net-zero economy. In this regard, our analysis provides several relevant elasticity estimates. For instance, we conclude that, relative to the 2022 average, a 25% increase in the market price of emissions allowances on the EU ETS would reduce the annual demand for emission permits from representative Portland cement plants by approximately 66%.

The Intergovernmental Panel on Climate Change and other research organizations have issued a variety of forecasts for the amount of CO_2 that will continue to be emitted in the year 2050. Such residual emissions would then have to be compensated by carbon removals in order to achieve a net-zero position. Our findings on the mirror S-shape of firms' willingness to abate suggest that unless carbon prices were to reach a range of several hundred Euro per ton of CO_2 emitted, Portland cement manufacturers would continue to emit at least 4% of their current emissions. Such projections must, of course, be qualified by their reference to contemporary manufacturing and abatement technologies.

In countries like Germany, governments seek to accelerate corporate decarbonization efforts by providing targeted subsidies to companies to reduce their emissions beyond the levels that current carbon prices incentivize. Such contractual arrangements are frequently referred to as "carbon contracts for difference" ("Klimaschutzverträge"). The

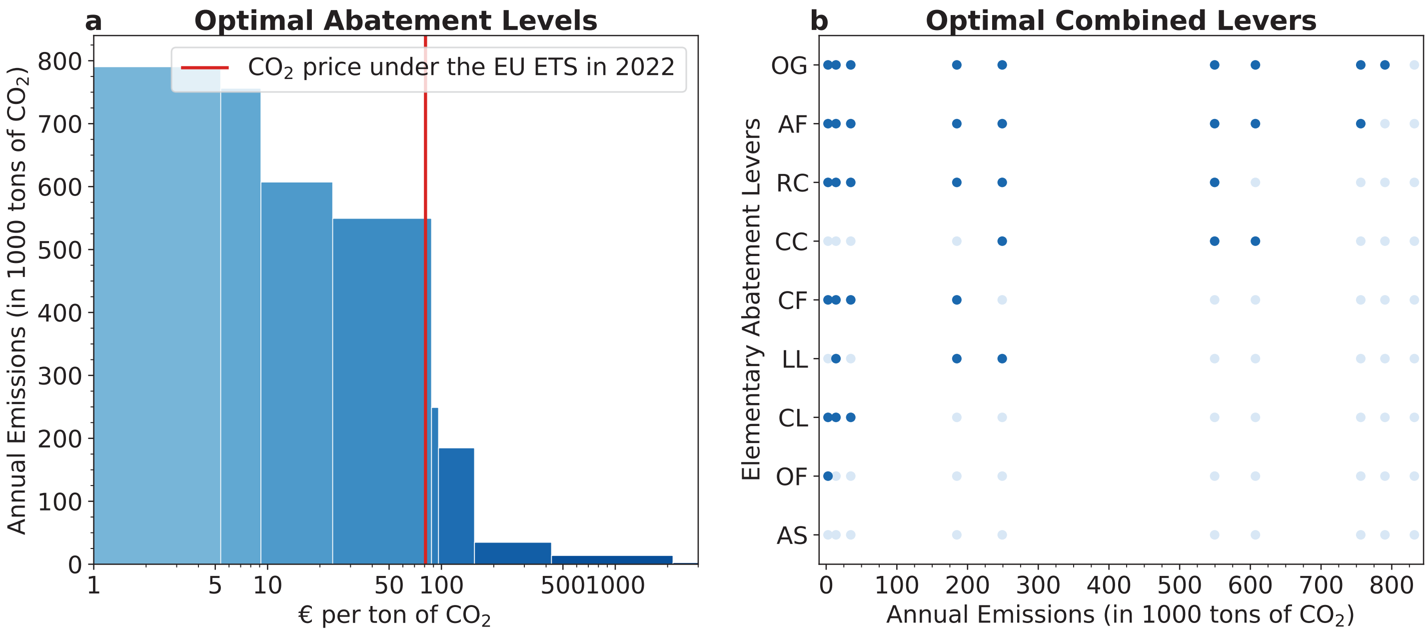


Figure 2. Optimal abatement for Portland Cement.

This figure shows (a) the optimal abatement at different CO_2 prices and (b) the optimal combined levers. Abbreviations are OG (Optimized Grinding), AF (Alternative Fuels), RC (Recycled Concrete), CC (Calcined Clays), LL (LEILAC), CL (Calcium Looping), OF (Oxyfuel), and AS (Amine Scrubbing).

abatement cost concept developed in this paper provides estimates for the minimum subsidy required for cement manufacturers to be willing to reduce their annual emissions to some target if the prevailing carbon price only incentivizes a higher level of emissions. For a company to be willing to enter into a contractual agreement that imposes maximal annual emissions of 184,823 tons of CO_2 (22% of the status quo emissions) at a representative plant, we find that the subsidy would need to be at least €8 per ton of CO_2, which is equivalent to an annual lump sum of about €3.0 million per plant. This calculation assumes that the prevailing carbon price is €81 per ton and, therefore, absent any contractual agreement, the company's optimal abatement response would be to emit 549,502 tons of CO_2 (66% of the status quo emissions) annually, as established in Figure 2.

Gunther Glenk, Anton Kelnhofer, Rebecca Meier, and Stefan Reichelstein (2023), "Cost-Efficient Pathways to Decarbonize Portland Cement Production", CEEPR WP-2023-12, MIT, June 2023.

Commentary.

Comments on Draft Revisions to OMB Circulars A-4 and A-94

By: Paul Joskow, Christopher Knittel, Deborah Lucas, Gilbert Metcalf, John Parsons, Robert Pindyck, and Richard Schmalensee

I. Background

With the promulgation of Executive Order 12291 in 1981, President Ronald Reagan introduced the requirement that any major proposed regulation require a benefit-cost analysis and that "[r]egulatory action shall not be undertaken unless the potential benefits to society for the regulation outweigh the potential costs to society". As further elaborated in President Bill Clinton's 1993 Executive Order 12866, "In deciding whether and how to regulate, agencies should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating. [...] Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach." Within the Executive branch, the Office of Information and Regulatory Affairs (OIRA) was tasked with overseeing the review of regulatory impact analyses (RIAs) by federal agencies.

Quantification of costs, and sometimes of benefits, is also required for other federal activities. Circular A-94, which was originally written in 1972 and updated in 1992, was drafted to provide guidance on benefit-cost analysis and cost effectiveness analysis of Federal spending programs, and to provide specific guidance on the discount rates to be used in evaluating Federal programs whose benefits and costs are distributed over time.

In 2003, Circular A-4 was drafted to serve as the set of instructions for agencies carrying out RIAs. For the past twenty years, the circular has been unchanged despite significant shifts in the economy and advances in the economics profession's understanding of best practices for benefit-cost analyses (BCAs). One concern is that because the Circular prescribed the level of discount rates, analyses became less reliable as market rates diverged from those assumed rates. Another issue has been the rising importance of climate change in policy analysis and a growing belief that the guidelines laid out in the 2003 circular were not well suited to this global externality with damages lasting, perhaps, for centuries.

The two circulars cover many similar issues, especially related to discounting future benefits and costs. Circular A-4 has perhaps received more attention among environmental and energy economists, especially given the importance of discounting for benefits and costs occurring far in the future (as is the case, for example, with climate change policies).

In 2023, OMB released drafts of updated Circulars A-4 and A-94 for public comment. The new A-4 draft was a significant revision of the original circular. It is also much more detailed: while the original circular was 48 pages long, the new draft is 91 pages long. The new A-94 draft includes updated guidance on the choice of discount rates that is consistent with the A-4 proposal. In response to the call for public input, the following comments were submitted by the authors along with additional signatories.

II. Submitted Comments on Circular A-4

We are writing to express our support for OMB's initiative to revise Circular A-4 in order to improve the benefit-cost analyses (BCAs) that underpin regulatory rule-makings by federal agencies. A revision that provides greater clarity and detail, that incorporates more recent theoretical, methodological, and empirical insights, and that better reflects fundamental valuation principles, is long overdue. The potential for improving the quality of regulatory decision-making and thereby increasing social welfare cannot be overstated, and you are to be commended for this ambitious undertaking.

We also appreciate the opportunity to comment on the specifics of the proposal. As discussed in our comments below, we support allowing a broader scope for included costs and benefits when deemed appropriate. We also agree that encouraging greater use of distributional analyses would be highly beneficial for better informing policy decisions and the public. However, we do not support prescribing the form of distributional weights nor requiring their use. On the related issues of assessing the costs of risk and discounting, the proposed methodology neglects the cost to individuals and society of systematic or aggregate risk. We suggest that the Circular be revised to require that the costs of aggregate risk be incorporated via the use of risk-adjusted discount rates or related methods where appropriate, with rates selected based on standard economic valuation principles and best practices in the private sector. With regard to the time period used to determine reference rates for discounting, in accordance with standard valuation principles and practices, we recommend using forward-looking estimates of future interest rates rather than rates based on long-run historical averages. Finally, we agree with the proposal to adjust long-run discount rates based on the logic that uncertainty imparts a downward slope to long-term discount rates, but we caution against detailed guidance that might suggest false precision about the size of those effects.

Looking to the future, because knowledge and views on best practices will continue to evolve, we encourage OMB to consider developing a systematic process for reviewing and periodically updating the Circular. While we are wary of frequent changes to the Circular that might inject politics into the process, we see merit in reviewing and updating the document more frequently than every twenty years.

Our focus in our comments is on three areas in particular: 1) scope of analysis; 2) distributional concerns; and 3) treatment of risk and discounting.

Scope of Analysis: The current A-4 states that an analysis "should focus on benefits and costs that accrue to citizens and residents of the United States. Where you choose to evaluate a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (p. 15). The draft revision, in our view, looks less like a change than an elaboration of the current guidance. The elaboration, however, is helpful in making the case for using a global measure of benefits and costs in certain circumstances and avoiding too narrow a measure of the geographic scope of costs and benefits. While this elaboration is certainly important given the international negotiations under the UN Conference of the Parties to address climate change, it could also be important for other global pollutants where multilateral efforts are underway to address the problem.

Distribution: We applaud OMB's focus on encouraging greater incorporation of distributional analysis into regulatory impact analyses. We particularly like the language on page 64 of the draft circular stating that "when distributional effects are relevant to the agency's decision, you should summarize your results and describe your analysis in a manner that supports transparency and comprehensibility for policymakers and the public." Providing distributional tables similar to those provided by the Joint Committee on Taxation when assessing the impacts of revisions to the tax code, for example, is a clear and transparent way to illustrate how a policy can impact different groups differentially (whether the groups are classified by income, wealth, geography, demographics, or labor force status, for example).

We do not support the routine use of distributional weights as discussed in section 10.e. on pp. 65–66. This approach involves a number of assumptions that are not transparent and on which there is not general agreement. First, there is a long-standing literature on the problems associated with using income to rank households according to their well-being. Wealth or some measure of lifetime income is a preferable measure, especially when looking at policies that affect the young or old. Moreover, it may be more relevant to focus on characteristics other than income or wealth when considering distributional outcomes. Distributional weights cannot be used in such cases. Second, even if one wants to use income as a measure of well-being, the use of distributional weights assumes, among other things, a social welfare function that is the same for all demographic and income groups (except for the level of income). There is no support in welfare economics for this assumption. Thus, the four questions posed on page 16 of the preamble are the wrong questions, in our view. Rather than try to refine estimates of the elasticity of marginal utility, we encourage OMB to focus attention on how best to report differential impacts of proposed regulations on different affected groups in a transparent and easily understood fashion.

Risk and Discounting: The draft Circular generally treats risk and discounting as separate issues, although in some essential respects they are not. It recommends adjusting for the effects of uninsured or uninsurable risk on individuals' welfare through the use of "certainty equivalents" that assign a cost to a specific risk exposure based on a measure of its disutility. Expected costs and benefits, inclusive of any certainty equivalent adjustments, are then discounted at a proxy for the social rate of time preference, which is usually taken to be a Treasury rate. This recommended procedure deviates from economic principles and standard practice in the private sector because it neglects the effect of aggregate or systematic risk on value (see, for example, the discussions in Lucas (2014) and Cherbonnier and Gollier (2022)). It is important for the Circular to recognize that aggregate risk affects value, and to provide guidance on how analysts should incorporate its effects.

Whereas it can be appropriate to discount future cash flows at Treasury rates when the associated risk is uncorrelated with future aggregate economic outcomes, when the risk is correlated some sort of risk-adjustment is necessary. We recommend the use of risk-adjusted discount rates, which can be identified using well-established fair value standards. This approach would also be consistent with the observation on pg. 32 of the proposed Circular that "Economists ordinarily consider market prices as the most accurate measure of the marginal value of goods and services to society."

An example may clarify the issues involved. Consider a proposed environmental regulation that would require installing pollution control equipment at oil refineries. The equipment would reduce annual production capacity and would reduce the incidence of some hypothetical non-fatal disease over a decade. The lost revenue to the refiner is systematically risky because demand for oil is positively related to the strength of the economy. The recommended approach would recognize that the lost revenues in future years are a cost to the private sector. However, discounting the average of those costs at a Treasury rate would neglect the effect on their value of the aggregate or systematic risk involved. The private sector would instead discount the expected future costs at a rate that includes a risk premium. Thus, in this case, the procedure recommended in the draft Circular would overstate the present value of losses to the refiner, and therefore overstate the cost of the regulation relative to its benefits.

Continuing with the oil refinery example, the benefits of this hypothetical regulation would include both medical treatment costs avoided and pain and suffering avoided resulting from the hypothetical non-fatal disease. An important question is how the presence or absence of insurance should affect the valuation of costs and benefits. For example, it is not generally possible to insure against pain and suffering, and individuals' benefits from reductions in the probabilities of pain and suffering will necessarily reflect their risk preferences. In this case, it is appropriate to adjust the expected total benefit from reduced pain and suffering to take into account the benefits of reducing individuals' risks, as is accomplished with the proposed guidance for finding certainty equivalents and adding them to costs or benefits. However, the appropriate discount rate is generally unaffected by whether or not individuals can insure against particular harm. If the cost of a harm is uncorrelated with the aggregate economy, it is appropriate to discount the adjusted totals at the proxy rate for the social rate of time preference.

Turning to another matter related to discounting, the draft Circular uses data on past Treasury interest rates, smoothed, to reach its recommended proxy for the social rate of time preference. It is not at all obvious why past rates rather than expected future rates should be applied to the projected future costs and benefits that affect regulatory decisions. We recommend development of forward-looking procedures for determining recommended discount rates. We believe the issue of smoothing deserves further attention. While smoothing can avoid short-term fluctuations in recommended discount rates that introduce noise, it hides the fact that the costs and benefits of introducing a regulation at any particular time may depend importantly on the state of the economy at that time, which will be reflected in expected future interest rates.

Finally, we support the proposal to adjust long-run discount rates based on the logic that uncertainty imparts a downward slope to long-term discount rates. We do caution, however, against detailed guidance that suggests false precision about the size of those effects as, for example, is suggested by the eight discount rates included in the table on page 30 of the Preamble document.

Summary: While we have focused on just a few issues in the draft A-4, we note in passing a number of changes we support and commend. The discussion of transfers (section 9) is useful, as is the acknowledgment of the potential role of general equilibrium modeling (section 7.h.). We also support the additional language recognizing the need for federal regulatory action (section 5.a.) that accounts for network effects as well as market power that manifests in non-price ways.

In closing, we applaud OMB for their work in putting forward a much clearer and detailed Circular A-4 draft. While we take issue with certain aspects of the revised circular, we believe that, once revisions have been made taking into account the points that we have raised, the final version should be invaluable in guiding federal agencies in conducting high-quality BCAs as part of the regulatory rule-making process. We appreciate the opportunity to review this document and look forward to the final version.

III. Submitted Comments on Circular A-94

We are writing in support OMB's efforts to improve the benefit-cost analyses (BCAs) that underpin agency decisions on federal policies whose benefits and costs are distributed over time. The potential to improve social welfare by adopting decision rules that incorporate up-to-date theoretical, methodological, and empirical insights, and that better reflect fundamental valuation principles, cannot be overstated.

We also appreciate the opportunity to comment on the specifics of the

Paul Joskow, Christopher Knittel, Deborah Lucas, Gilbert Metcalf, John Parsons, Robert Pindyck, and Richard Schmalensee (2023), "Research Commentary: Comments on Draft Revisions to OMB Circulars A-4 and A-94", CEEPR RC-2023-04, MIT, July 2023.

proposal. Our focus here is on the related issues of assessing the government's cost of capital and discounting. The proposed methodology would perpetuate the long-standing practice of using Treasury rates for discounting in most instances, which has serious shortcomings. It neglects the cost to individuals and society of systematic or aggregate risk; mistakes the government's cost of capital for its borrowing rate; and introduces avoidable biases into BCAs. We suggest that the Circular be revised to require that the price of aggregate risk be routinely incorporated into the base case valuation of costs and benefits when feasible. That could be accomplished via the use of risk-adjusted discount rates, or with alternative methods that are also consistent with standard economic valuation principles and best practices in the private sector.

To elaborate, economic principles, and standard valuation practices in the private sector, both recognize the importance of the effect on value of aggregate or systematic risk. The relevance of those principles to government valuations are discussed at length, for example, in Lucas (2014) and Cherbonnier and Gollier (2022). Recent survey evidence suggests that most economists believe that governments should incorporate risk-adjustment into valuation procedures (see Christian Gollier, Frederick van der Ploeg and Jiakun Zheng, (2022)).

The logic behind approximating the government's cost of capital with that of the private sector, rather than equating it to Treasury rates, rests on several observations. First, the aggregate or systematic risks associated with an activity is generally similar, whether it is undertaken by the private or public sector. Second, like the private sector, the government cannot eliminate systematic risk through diversification. Rather, the risk eventually has to be absorbed by some combination of tax and spending changes. Hence taxpayers and other government stakeholders function as equity holders in risky government activities. Using risk-free Treasury rates for discounting treats the imposition of aggregate risk on taxpayers and government stakeholders as having no cost to society. That assumption is inconsistent with the preferences revealed by the substantial payments that individuals demand—in the form of higher return—for bearing systematic risk.

Discounting at Treasury rates creates practical as well as conceptual problems. The treatment of asset sales is one such example. Because the private sector generally discounts the net cashflows from an asset at a higher rate than the Treasury rate, it typically places less value on assets than does the government. The more systematic the associated risk, the larger the valuation gap and the larger the bias in favor of government ownership. That discrepancy also creates budgetary arbitrage opportunities: The government will appear to profit when it buys risky assets from the private sector that it funds by issuing safe debt. There is a budgetary gain even when the change in asset ownership has no material economic or distributional effects. The discrepancy also has the effect of inhibiting asset sales by the government that could improve efficiency when the private sector has an operational advantage. The draft Circular recognizes this as a potential problem and allows for discounting at private sector rates in such instances. However, it is hard to justify that work-around when the maintained assumption elsewhere is that Treasury rates represent the government's true cost of capital.

Using Treasury rates for lease-purchase analysis creates a related bias against leasing. As a first approximation and assuming leasing provides no additional services, the present value of lease payments that are discounted at market rates should equal the market price of the leased asset. When the government discounts the same lease payments at lower Treasury rates, leasing appears to be more expensive than buying. This highlights a more general phenomenon: Whenever the government makes a purchase from the private sector, the price paid is inclusive of associated private sector capital costs. It is only in situations involving explicit discounting of future government cash flows that an artificial wedge is introduced between government and private sector valuations.

The draft Circular leaves the door open for risk-adjustment in some cases, and suggests that analysts use the "certainty equivalent" approach as described in the draft Circular A-4. The Circular A-4 guidance directs analysts to assign a cost to a specific risk exposure based on a measure of its disutility. Expected costs and benefits, inclusive of any certainty equivalent adjustments, are then discounted at Treasury rates that proxy for the social rate of time preference. Theoretically, it is possible to incorporate an adjustment for the price of systematic risk into the calculation of a certainty equivalent. That adjustment will generally require making inferences based on market prices or rates. When done correctly, the resulting valuation will be the same as if a risk-adjusted discount rate had been directly applied to projected costs and benefits. However, while this theoretical equivalence is noted in finance textbooks, certainty equivalents adjusted for the cost of systematic risk are almost never used in practice. The draft Circular A-4 does not suggest that the price of systematic risk should be incorporated into certainty equivalents, nor does it offer any guidance on how to do so. Considerations of transparency and auditability suggest that the government should favor procedures — such as risk-adjusting discount rate — that are in keeping with standard valuation practices.

An implication of recognizing the price of aggregate risk is that the appropriate discount rate will vary across projects and policies with different exposures to aggregate risk. The need to select policy or program-specific discount rates would entail additional costs for agencies, especially during a transition period during which analysts would need additional training and procedures were being established. However, the approach we favor for most applications — risk-adjusting discount rates using well-established fair value principles — could be implemented in a way that entails modest additional costs to the government, and that results in estimates that are more disciplined, transparent, and auditable than those produced using Treasury rates for discounting. Agencies could draw on the professional expertise that has developed to support valuations in the private sector. Alternatively, OMB could centralize the process, selecting and periodically updating a schedule of risk-adjusted rates, just as it does now for real and nominal Treasury term structures.

In closing, we appreciate the effort that has gone into improving the clarity of the guidance on how the costs and benefits of federal policies whose benefits and costs are distributed over time should be assessed, and the care that is taken to offer guidance that in most respects closely conforms with economic principles and best practices. We believe that a revision that also brings the selection of discount rates in line with economic principles and best practice would greatly improve government decision-making. We appreciate the opportunity to have reviewed this document and look forward to the final version.

Vivienne Zhang (2023), "Improving Predictability of Wind Power Generation Using Empirical Data", CEEPR WP-2023-16, MIT, September 2023.

Research.

Improving Predictability of Wind Power Generation Using Empirical Data

By: Vivienne Zhang

Wind electricity generation grew exponentially in the past two decades from 6 billion kilowatt-hours (kWh) in 2000 to 380 billion kWh in 2021 and today accounts for more than 9% of total utility-scale power generated in the US. However, wind power is an intermittent renewable resource, and accurate forecasting of wind power generation is essential to grid management. Improving the predictability of wind power generation is challenging for many reasons, one of which is a lack of empirical data, which are proprietary and confidential. While there exist a multitude of studies on how to build the best machine learning model using simulated data, few studies are based on empirical data from a cluster of wind farms.

This study uses actual generation data between 2016 and 2021 from seven wind farms in the United States ranging from ~50 Megawatts (MW) to 235 MW in size. In addition to the generation datasets, we also collected local public weather station data from the National Oceanic and Atmospheric Administration (NOAA), as well as wind speed forecast data, which were extracted from the National Weather Service (NWS) archive for the first time for the purpose of studying wind power forecasting. The approximate locations of the weather stations and the wind farms are shown in Figure 1. We then use the same machine learning method, a Long Short-term Memory (LSTM) network, to predict wind power generation for all seven power plants. While controlling for the prediction method, we run two experiments: one using only the past generation and weather measurement data; the other using the former plus the wind speed forecasts from NWS.

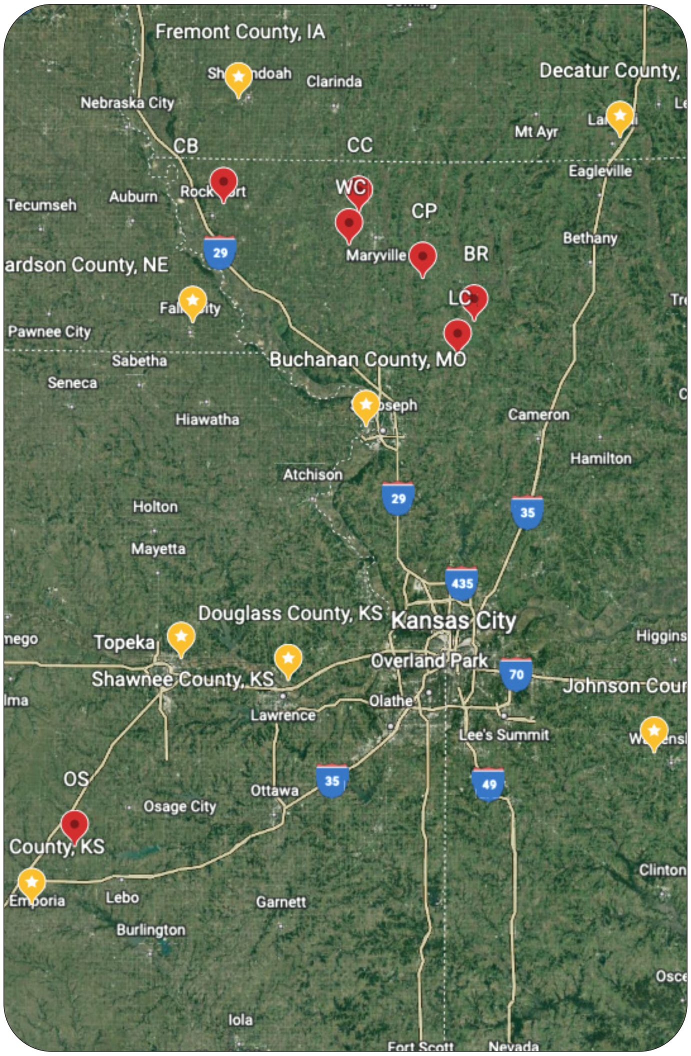


Figure 1. Locations of Wind Farms vs Local NOAA weather stations.
(Red represents the wind farm, while yellow is the weather station)

We find that the predictability of wind power generation can be significantly improved when we add wind speed forecasts from the NWS to the input dataset, instead of using only past weather measurement data. All seven power plants see an increase in wind power generation predictability by more than 5% as measured in Mean Absolute Percentage Error. The highest improvement in predictability is more than 8%. The result is significant given that experiments using more elaborate machine learning neural networks consistently show less than 2% improvement. A figure plotting a sample of the two predictions vs ground truth data is shown below. This result can be explained by the fact that wind speed changes are often stochastic. It may be difficult for machine learning, a statistics-based method, to capture the limited statistical relationship between past and future wind speeds, the deciding factor in wind power generation. On the other hand, wind speed forecasts from the NWS are made by physics-based methods, which may explain why the predictions follow the ground truth data more closely when sudden changes occur. It should be noted that wind speed forecasts are made every 3 hours by NWS while wind speed changes happen much more frequently. This suggests that further improvement may be obtained if wind speed forecasts are made in greater time granularity.

The economic effect of improvements in wind power forecasting accuracy is then studied using a simulation with market data from the Midcontinent Independent System Operator (MISO) and the Southwest Power Pool (SPP). Depending on the trading strategy, we find that while the more accurately forecasted energy can generate annual savings of more than $300,000 in one market, it can also lead to losses in another. This is because earnings are highly dependent on the price differences in the Day-ahead and the Real-time electricity market, which vary significantly across markets and time periods. More research is needed to assess the economic benefits of more accurate wind power generation forecasting.

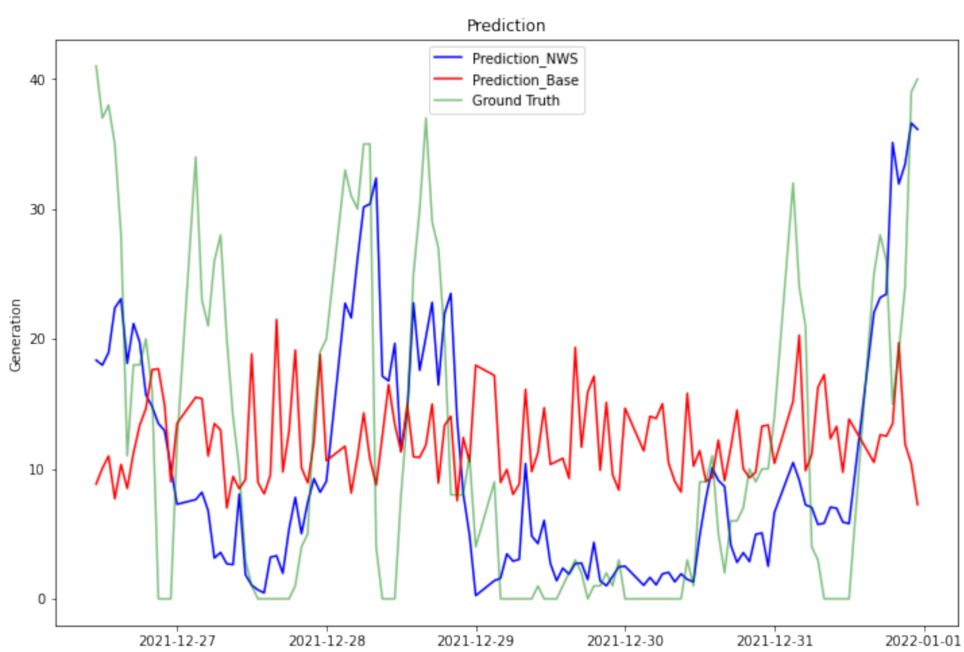


Figure 2. LSTM Performance - 24 hour-ahead: Baseline (red) vs NWS (blue) vs Ground Truth (green) for one wind project.

Research.

Another Source of Inequity? How Grid Reinforcement Costs Differ by the Income of EV User Groups

By: Sarah A. Steinbach and Maximilian J. Blaschke

With tightening carbon emission regulations in the transportation sector, more and more consumers are switching to electric vehicles (EVs). However, charging a high number of EVs poses challenges to the distribution grids: Most consumers favor charging their EVs at similar times during the day, especially in the early evening hours. This parallel charging of multiple EVs could lead to significant load peaks causing overloads within the grids (Clement-Nyns et al. 2010; Lopes et al. 2011; Muratori 2018). These overloads increase with EV adoption and depend on the EV model choice and the applied charging patterns. All these factors may be correlated with socio-economic attributes, especially household income (see, e.g., Xue et al. 2021; Sovacool et al. 2019; Kelly et al. 2012; Lee and Brown 2021; Gauglitz et al. 2020). Therefore, grid operators may have to over-proportionally enhance the grid infrastructure in areas with many high-income households. Our paper investigates how the necessary grid reinforcement costs differ between lower and higher-income neighborhoods. From these calculations, we quantify the over-proportional grid reinforcement cost impact of higher-income EV users, its potential to cause energy inequity and derive policy recommendations accordingly.

We simulate electricity usage for two neighborhood types: below-average (lower) and above-average (higher) income. For these two neighborhood types, we assign respective EVs considering adoption and model choices and fit the corresponding mobility behavior. We use representative distribution grids in urban, suburban, and rural settings to account for the differing structure and load capacity. After allocating the electric vehicles amongst the grid nodes, the simulations check each setting for overloads and derive the grid reinforcement cost asymmetry between the two neighborhood types. To consider the most challenging season for electricity usage, we perform the simulation over a week in December.

Based on simulated load profiles, we investigate the grid overloads occurring for below- and above-average-income rural, suburban, and

Sarah A. Steinbach and Maximilian J. Blaschke (2023), "Another Source of Inequity? How Grid Reinforcement Costs Differ by the Income of EV User Groups", CEEPR WP-2023-13, MIT, July 2023.

urban neighborhoods. This overload analysis is relevant for grid planning, as it displays which neighborhoods require prioritization. In all area types, higher-income neighborhoods would experience significantly more grid overloads, putting these neighborhoods higher on the grid operators' agenda for grid reinforcements. As the number of overloads and hence the probability for a blackout differ significantly between lower and higher-income neighborhoods, the importance of including socio-economic factors such as income in grid planning models becomes apparent.

Next, we derive the related grid reinforcement costs to mitigate the overloads previously outlined and stabilize the grid. The average reinforcement costs to be expected are illustrated in Figure 1 shown below.

We see 50% additional grid reinforcement costs for higher-income neighborhoods in the rural, 3,266% in the suburban, and 478% in the urban grid compared to lower-income neighborhoods. The reinforcement costs in the rural grid do not differ that much as this grid offers the least resilience. An upgrade of its bottleneck, the transformers, becomes inevitable even for lower EV charging loads.

The asymmetries in grid reinforcement cost illustrate the necessity for grid operators to include socio-economic factors such as income in their grid planning models to represent future grid costs adequately. When extrapolating our findings to the around 119 million residential buildings in the EU and accounting for their distribution to rural, suburban, and urban areas, the potential grid cost asymmetry between higher- and lower-income neighborhoods could reach approximately €14 billion.

In order to derive appropriate mitigating policy measures, we further analyze the impact of the underlying drivers for the additional grid reinforcement cost of higher-income neighborhoods. We quantify the standalone impact of differences in EV adoption, model choice, and

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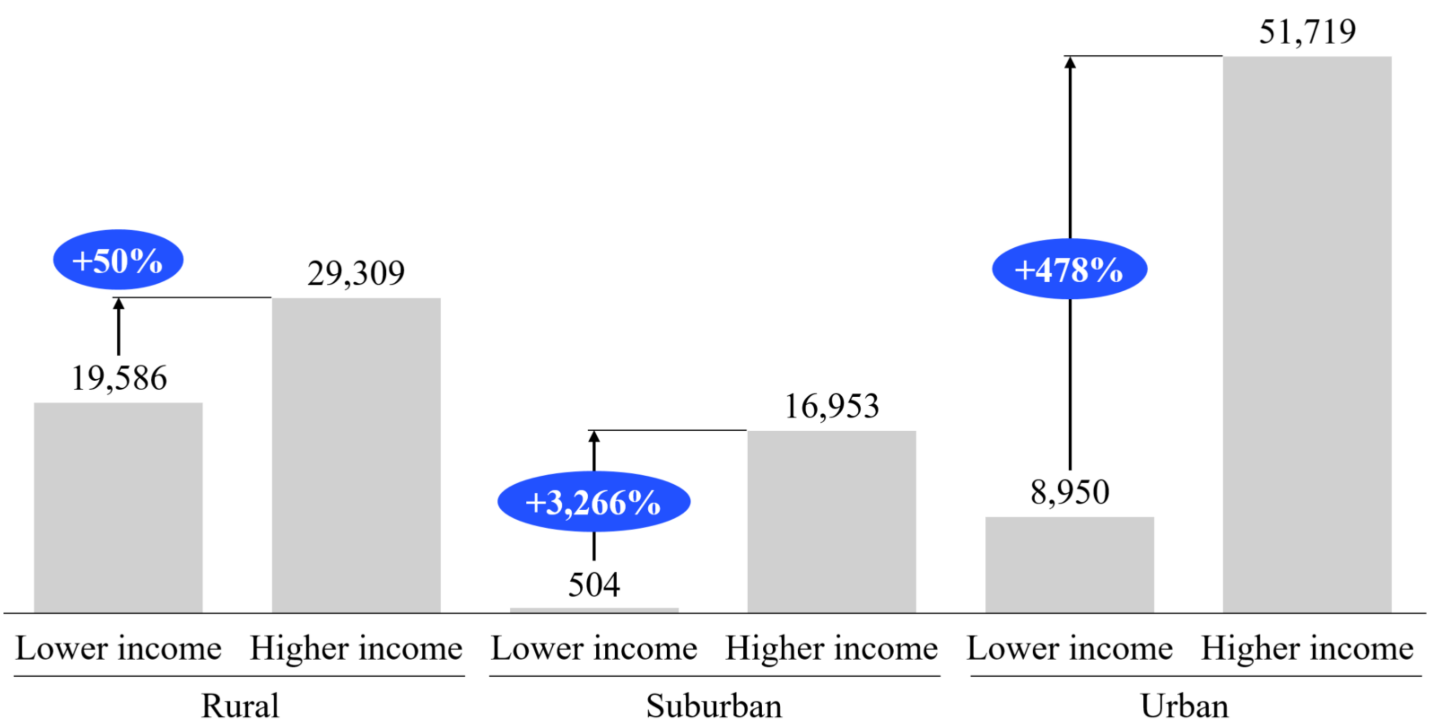

Figure 1. Average simulated grid reinforcement costs (in €) in December.

driving patterns by neighborhood type. If EV adoption were equally distributed over all neighborhoods, the grid reinforcement cost asymmetries would shrink significantly. This effect, however, is partly caused by a related grid cost increase for lower-income neighborhoods. Nonetheless, our results show that even if equal EV adoption levels across income levels could be achieved, significant additional grid reinforcement costs for higher-income neighborhoods prevail, especially for the suburban and urban grids. Driving patterns strongly impact grid cost asymmetry, while the effect of model choice is relatively small. These findings indicate that policymakers may foster EV adoption with all model sizes but focus more on reducing peak-hour charging to mitigate some behavioral effects of higher-income households.

Residential grid reinforcement costs are currently paid for via the consumer electricity price. If grid costs increase, the electricity price inflates for all consumers across neighborhoods. Due to their higher total electricity consumption and related higher electricity costs, higher-income neighborhoods carry more of the grid reinforcement costs in total. However, as they only consume 16%-18% (based on the area type) more electricity than lower-income households, this contribution fails to offset the massive additional grid reinforcement costs caused. Furthermore, grid operators often split grid costs into a base rate in addition to a volumetric (per kWh) component. This base rate is not scaled with regards to consumption and hence further limits the grid cost contribution of higher-income households (Bundesnetzagentur 2020). With household electricity prices at a record high (e.g. 32.63ct/kWh in 2021 in Germany and quickly increasing during the European Energy Crisis in 2022 (Bundesnetzagentur 2022; Statistisches Bundesamt 2022; Guan et al. 2023)), consumers have to expect further across-the-board electricity price increases to cover the additional grid reinforcement. This, however, is inequitable with respect to the principle of fairness according to contribution. As this grid reinforcement cost asymmetry can be traced back to higher-income neighborhoods, equitable cost allocation would require higher-income households to fully bear this cost asymmetry, not affecting the electricity prices of other consumers.

Policymakers should consider alternative electricity pricing models that adjust for maximum electricity loads induced. They could also encourage a dynamic electricity pricing strategy increasing peak-time electricity prices for households. EV adoption greatly impacts the magnitude of the inequitable grid cost allocation. As it is not desirable to reduce overall EV adoption and limit the electrification of mobility, policymakers could reduce the inequity in cost allocation by increasing subsidies for EV adoption in lower-income households, where EV subsidies have shown the strongest impact on EV adoption (Sheldon et al. 2023). However, households that cannot afford an electric vehicle will not benefit from any of such actions but still face higher grid costs.

We contribute to current research by quantifying grid cost asymmetries with electric vehicle charging, considering socio-economic factors. With this contribution, we illustrate the importance for researchers and grid operators to include socio-economic factors in their simulations and support policymakers in factoring energy equity issues into future electricity pricing designs and subsidy schemes. This article provides new insights into the cost of the sustainable mobility transition and sheds light on the intensifying energy inequity.

Commentary.

The EU Commission's Proposal for Improving the Electricity Market Design: Treading Water, But Not Drowning

By: Carlos Batlle, Tim Schittekatte, Paolo Mastropietro, and Pablo Rodilla

A Herculean task accomplished: keeping the building standing during a long-lasting earthquake

Over the past year and a half, European energy policymakers have faced an extremely complex conjuncture. The electricity price crisis, triggered mainly by Russia's invasion of Ukraine, has put very high pressure on European institutions to intervene and subsequently to reform the market design. With the alleged goal of protecting customers, governments of several Member States advanced controversial proposals, pointing in different directions. However, crises are not the best time to carry out major reforms and the European Commission (EC), with the proposal published in March 2023, did an excellent job in "defusing" a risky overhaul of the European electricity market design. The biggest challenge was to avoid entering into a regressive process that would have disabled some of the fundamental tools that have supported an increasingly efficient integration of the Union's electricity systems. The proposal preserves the key role of short-term electricity markets, deactivating certain loud and unjustified criticism (which for instance started by questioning the fundamental role of marginal pricing as signals that inform an efficient economic dispatch and medium-term planning).

For this reason, we highly welcome the proposal from the EC, though there are some elements of the proposal that, in our view, require further analysis. We discuss these elements in this research brief. The EC has put forward a large battery of measures, covering different dimensions and with very different potential impacts on the market design. Our review is not intended to be exhaustive. We focus on what we consider to be four key elements: i) the promotion of long-term contracting, ii) interventions during electricity price crises, iii) the strategy for an efficient supplier risk management, and iv) flexibility support schemes and capacity remuneration mechanisms (CRMs).

1. Dealing with long-term market nothingness

The EC rightly identifies the lack of liquidity in long-term electricity markets as one of the main shortcomings to be addressed. The risk hedging provided by long-term contracts is essential to accelerate the deployment of low-carbon technologies while mitigating, to the extent possible, the impact of periods of high spot prices on consumers. This is particularly important for independent project developers, who should have access to risk-hedging instruments on equal terms as other market participants, such as vertically integrated incumbents that can rely on the natural hedge provided by their retail portfolio.

In the months leading up to the publication of the proposal, there was an intense debate between two polar positions on how to improve the access to risk-hedging instruments. On one side, there is the so-called Power Purchase Agreements (PPAs) approach, which argues that no meaningful market design reform nor significant regulatory intervention is needed. Proponents of this approach claim that market agents should be left to their own devices; free to enter into long-term bilateral agreements. Only some initial regulatory support might be needed to accelerate long-term contracting by eliminating some regulatory or economic barriers. The main argument for this approach is that it allows for innovation in contracting arrangements to flourish and limits the influence of the government on the final supply mix. On the other side, the Contracts-for-Difference (CfDs) approach argues that only a centralized mechanism promoted by the government/regulator, buying on behalf of end users, would lead to a high enough supply of long-term contracts needed to support the projected investments in low-carbon resources. Besides the low risk of having the government as guarantee, other important arguments for this approach are price transparency, the creation of a level-playing field for all project developers to compete on equal footing, and the possibility to coordinate generation and transmission access and expansion.

In its proposal, the Commission clearly favors the PPA approach, although it does not exclude the possibility of introducing CfDs to complement the PPA market if necessary. Overall, the proposal does not represent a significant change to the status quo, as neither approach is new to the electricity sector.

What we miss in the proposal is a more thorough diagnosis of the market-incompleteness problem, i.e., the reasons why long-term power markets have never worked. Also, why PPAs have (somehow) seen significant uptake in some jurisdictions and not at all in others. There is no assessment that explains why PPAs have not grown to the minimum level necessary to create a liquid long-term electricity market open to all parties, both supply and demand. The main proposal to foster liquidity in PPA markets is the reduction of off-taker payment default risk, which should be made available for PPAs signed with "actors that face entry barriers". As we discussed in a previous paper , in our view the main reasons behind market incompleteness are:

- lack of demand-side participation in long-term markets, partly due to transaction costs but mainly due to the trust in governmental intervention in times of stress (confirmed by this crisis, as well as by Article 66a of the proposal, discussed later).

- vertical integration between generation and retail of the incumbent utilities, combined with an asymmetric distribution of diversified generation portfolios.

The fact is that demand-side concerns about hedging against potential future high prices were negligible before the crisis. The problem was not that end users wanted to enter into long-term contracts and could not because of barriers that prevented them from doing so. End users just never felt the need to. We keep on wondering what the reasons are. Our claim has so far been that electricity end users have always relied on some sort of government parachute. After this crisis, that is no longer an expectation, it actually happened. In those jurisdictions where retailers are publicly owned (directly or indirectly by the national, regional, or municipal government), governments/regulators have a straightforward tool to take the lead and promote among their customers this long-term hedging strategy. These retailers are also naturally less risk averse to assume the volume risk involved (see discussion later). But why should we expect that the situation is going to change when retailers are not publicly owned?

This matter is directly related to the second factor mentioned above. As we discussed in a previous publication, why would vertically-integrated utilities be willing to offer long-term hedges to competing investors in renewable sources and retailers, rather than investing themselves and allowing their own retail arm to benefit from their natural hedge? It is extremely important to address this issue if a liquid long-term market is to be developed. For this reason, if the CfD approach was not considered suitable for further development, we proposed in the same paper the introduction of a market-maker obligation in organized forward markets. We strongly recommend that such measure is at least further explored.

The EC proposal attempts to circumvent the vertical-integration problem by favoring, in a potential CfD market, those generation projects that sign PPAs with "buyers that face difficulties to access the PPA market." However, it is not clear how these customers/retailers would be identified without introducing arbitrariness in the allocation of CfDs. Also, the consequences of this approach on the long-term dynamics of the market can only be guessed at. In addition, this clause does not solve the problem of independent project developers. In most jurisdictions, buyers that face barriers to entry (independent retailers?) have small portfolios, which are largely insufficient to act as counterparties for all the new generation needed. It is therefore likely that independent developers would still not be able to find sufficient demand willing to sign long-term contracts.

CfDs are a tool for regulators to take action to address the problems just discussed. They are not needed in power systems where there are large state-owned incumbents, both on the generation and the retail side. In this situation, the will of the government may be sufficient to induce these companies to dynamize the market for long-term contracts. These incumbents could even favor demand segments that are considered to be the most suitable counterparty for the PPA contracts. It is important to note that in most cases the PPA contract details are not public, not even the price. To avoid such a scenario unfolding, an obligation to improve the transparency of PPAs should be required. Centralized markets for CfDs are transparent by nature.

Last but certainly not least, the proposal does not address how the format of these long-term contracts should be defined to maintain efficient economic signals for generators (and end-users). During the consultation phase, several stakeholders highlighted the distortionary impact that different settlement arrangements may have on the dispatch of market agents (we also discussed this issue in the article previously referenced). Guidance at the European level on this highly controversial topic will be needed at some point to avoid a proliferation of a diverse set of contract formats leading to fragmentation within the internal electricity market. ACER would be a perfect institution to lead this effort.

2. Consolidating the unavoidable intervention, but making it unpredictable

With the inclusion of Article 66a, the proposal also formalizes the conditions under which an "electricity price crisis" can be declared. We understand that pragmatism requires the inclusion of some sort of emergency price buffer. In this respect, we welcome the fact that future electricity price crises will have to be identified as such by the Commission at the regional level, based on a pre-defined set of criteria. This can avoid potential opportunistic behavior by Member States.

However, while it sets out the conditions under which an "electricity price crisis" may be declared and the extent to which Member States may apply targeted public intervention in the pricing of electricity for residential and small to medium-sized enterprises, nothing is mentioned about where the money would come from to finance these interventions. Just as the proposal sets out guidelines, including specific limitations, on the type of price setting intervention that Member States can introduce with regard to end users (i.e., a retail market intervention), one would expect the proposal to also outline the wholesale market interventions that Member States can (and cannot) resort to in the event of a declared "electricity price crisis". If such a crisis were to recur in the next couple of years, the payouts from government-promoted CfDs will not suffice to mitigate an affordability shock. The CfD volumes are not sufficient and renewable production profiles do not necessarily align with consumption profiles. Member States with strong public finances could indeed use their government budgets to protect consumers from affordability concerns but it seems unlikely that this will be the case for all Member States. The temptation to resort to wholesale market interventions (e.g., revenue caps, the Iberian exception, mandated auctions etc.) seems strong, while the proposal does not contain provisions to avoid a repetition of such a chaotic scenario.

The problem is not necessarily the introduction of a wholesale market intervention per se, but uncertainty about when, how, and to what extent market players can expect such intervention. Uncertainty about the type of intervention to be expected during stress events discourages investment in new generation and is inconsistent with the call for improved long-term hedging, which is arguably the most important element of the proposal. If market participants (on both the supply and demand side) do not know the rules that will apply during future periods of sustained high prices and cannot quantify their impact in advance, they cannot define an efficient hedging strategy and are less likely to enter into long-term contracts.

If the Commission recognizes that there is a price level that should not be exceeded for long periods of time, then it will be more efficient to have recourse to a market mechanism that provides such specific protection. In an earlier working paper, we proposed the introduction of what we called Affordability Options (AOs). The detailed design is less complex than direct intervention in retail prices, significantly less distortive, and predictable. With AOs in place, there would be no risk of wholesale market intervention because the impact of AOs on market settlements can be predicted by agents (i.e., the transferring inframarginal rent between generation and demand is pre-agreed at the expense of an option premium payment). Such a mechanism facilitates the definition of their hedging strategy. Furthermore, the design of AOs would maintain a certain degree of end user exposure to short-term market signals, thereby improving dispatch efficiency.

3. Hedging obligation on suppliers and the room left for retail competition

Another key guideline included in the proposal is to enforce a certain level of financial coverage for suppliers. The idea is to avoid harmful bankruptcies in the event of unexpectedly high prices. We find this initiative a sensible lesson learned from the price crisis that we have experienced. However, this approach also entails significant implications that are not discussed in the proposal. Independent suppliers are exposed to a significant volume risk. In most cases, customers will be able to switch regardless of the terms of the PPAs and the estimations made by the supplier. A sudden drop in the number of customers or in their demand may lead to a default of the supplier, since it may not be able to honor its PPAs (which may be backed by state guarantees, leading to at least the partial socialization of such default).

The hedging obligation may make sense, but once again it reinforces the already largely advantageous competitive position of suppliers belonging to a vertically integrated holding company. In this context, we believe that it is essential to launch an in-depth debate to reconsider the role of suppliers, and in particular whether it is appropriate to unbundle the price hedging task from all the other tasks that suppliers might be expected to develop (energy efficiency advice, aggregation, demand flexibility, etc.). Further discussion of the future of retail markets in such a scenario is beyond the scope of this brief but it is certainly an issue that needs to be considered carefully.

Also, full hedging may not be the best strategy for all end users. Hedging through long-term contracts stabilizes electricity prices but does not imply a net reduction in bills over a sufficient time horizon. This stabilization (which also comes at the cost of a risk premium) may be worth it for those customers who may be subject to significant financial distress if electricity prices suddenly spike (e.g., vulnerable households or electricity-intensive businesses). However, there may also be a significant proportion of customers for whom electricity price volatility is not a financial problem. It is not necessarily efficient to force suppliers to hedge the demand of these customers and to require them to include a fixed-price contract in their offer.

Besides hedging via retail contracts, already today an important volume of electricity production is covered by CfD contracts that are backed up by governments. This volume is expected to rise, even though the ultimate scope of CfDs will depend on the dynamics between PPA vs CfD approach, as discussed in the previous section. In periods of high spot prices, these contracts are in-the-money, i.e., leading to revenues that can be returned to end users (details depend on the national arrangements). As already seen during the energy crisis, this revenue can be redistributed to mitigate to some extent impacts on consumer bills. The Commission's proposal states in this respect that: "the revenues collected when the market price is above the strike price [shall be] distributed to all final electricity customers based on their share of consumption (same cost / refund per MWh consumed)" while at the same time "the distribution of the revenues to final electricity customers [shall be] designed so as not to remove the incentives of consumers to reduce their consumption or shift it to periods when electricity prices are low and not to undermine competition between electricity suppliers".

We have three concerns with these provisions. First, there is an inherent trade-off between distributing revenues from a CfD based on per-MWh consumed basis and limiting the removal of the incentives of consumers to reduce their consumption. For example, in case the consumption would be measured on monthly, quarterly, or even annual basis, those consumers that really made an effort to scale back their consumption would receive less relief from the CfD revenues. As such incentives are distorted. The least distortive approach would be to use the revenues of the CfDs for lump-sum payouts to consumers. These lump-sum payouts could be the same for consumers with a certain consumer class (e.g., residential, commercial, industrial) or differentiated based on income or other proxies. Second, in case the volume of CfDs continues to rise, the redistribution of its revenue serves as an intrinsic hedge for consumers entitled to the pay-outs. The hedge is not perfect, as not the entire consumption volume is covered, and the capture value of renewables and the load-weighted average price of consumers is expected to diverge. Anyhow, for some consumers, the ones for which the volatility of the electricity price does not represent a financial problem, such mechanism could be enough to serve as bill protection. In that case, there is little role for retailers regarding the price hedging task as the government takes over that task (this takes us back to the argument raised in the second paragraph of this section). Third, the CfDs will not always be in-the-money. During periods of relatively low spot prices, which sooner or later will resurface, the CfD contracts will be a net cost. The reform does not mention that those consumers that profit from the redistribution of revenues during periods of high spot prices, shall also be the ones that carry the burden during periods of low spot prices. It is also not clarified how to design the format of such payments. Preferably payouts and payments should be symmetrically designed; a certain volume of CfD contracts is associated with a certain consumer group and the revenue over a certain period (which can be positive or negative) shall be settled via lump-sum payouts/ payments distributed across the members of that consumer group. It is important to provide European guidance in this respect as there might be a temptation to favor certain consumer groups when it comes to payouts and change the arrangements when suddenly the CfDs turn out to be out-of-the money, e.g., leading to an unleveled playing field between electro-intensive industry within the internal European market.

4. Flexibility support schemes and CRMs: wrenches for bolts, hammers for nails

The proposal, as other recent legislative initiatives from the Commission, has a strong focus on flexibility. It foresees the introduction of specific assessments of flexibility needs, indicative national objectives for two of the "new" technologies called to provide this flexibility, i.e., demand-side response (DSR) and storage, and flexibility support schemes that should drive their deployment. At the best of our knowledge, the proposal also provides for the first time in European legislation a definition of flexibility: "flexibility means the ability of an electricity system to adjust to the variability of generation and consumption patterns and grid availability, across relevant market timeframes". We welcome this necessary definition, but we remark that it has a significant overlap with the security of supply problem (the definition would be correct also if we substitute "flexibility" with "security of supply" or "reliability"). Flexibility can be interpreted as a "short-term dimension'' of security of supply, and it should be treated as such in European legislation. This problem can be addressed through the introduction of capacity remuneration mechanisms (CRMs), as for instance it is the case for the Italian mechanism.

Totally aware of this synergy, European policymakers propose that, if a CRM is in place, this regulatory instrument should be used to promote flexibility from DSR and storage. This approach violates an important tenet of economic regulation, i.e., different regulatory objectives are better pursued through different regulatory instruments. CRMs aim at driving the system towards a resource mix that allows to fulfil the reliability criterion set by the regulator. If designed efficiently, it will target the kind of scarcity conditions expected in the system. If the main reliability threat concerns the very short-term time horizon (e.g., an expected lack of ramping capability), the CRM will automatically target flexibility. However, if reliability concerns are more related to resource adequacy (e.g., a dry season in a hydro-dominated power system, an extremely hot summer that forces to shut down nuclear plants, or a full week without wind in the North Sea), the CRM should not be artificially tilted towards flexibility.

In this context, it must also be remarked that the electricity price crisis showed us that European power systems are not as capacity constrained as we used to think. Besides the three (hydro, nuclear, wind) factors previously mentioned, power systems with dwindling gas reserves (or, in the future, hydrogen, biogas, or even electro-chemical reserves) rapidly become energy constrained, reducing the value of flexibility to guarantee security of supply. Symptoms of capacity-constraint systems are infrequent scarcity prices, in contrast, symptoms of energy-constraint systems are sustained periods (weeks or more) of very high prices. It is hard to forecast the kind of scarcity conditions that European power systems will have to face in ten years, and they may vary significantly among Member States. To tackle them, we need dynamic and efficiently designed CRMs, potentially harmonized at the European level, not mandatory requirements for a specific reliability service, as flexibility, which may not be required the same way in all European power systems.

Furthermore, by requiring CRMs to support flexibility from DSR and storage, the proposal may force regulators to introduce specific subproducts in their mechanism and to define specific requirements for these subproducts. This segmentation of the CRM may result in inefficient outcomes. Brought to an extreme, this approach may end up mimicking central planning, with several targets for specific product, each one tailored to a certain technology. Although this may become progressively more difficult in the future, from a regulatory point of view, it is better to define a single CRM product (tailored to the reliability target and the expected scarcity conditions) and let different technologies compete for its provision.

This does not mean that DSR and storage should not be supported. If the Commission believes that there are market failures or externalities that are impeding an efficient deployment of these technologies, specific support schemes should be introduced (proposals in this sense are being discussed in several Member States). As for renewables, these support mechanisms should minimize distortion of market competition.

A similar reasoning can be applied to the peak shaving product defined in the proposal. According to the high-level description of this service provided in the proposal, the peak-shaving product is a short-term product to be added to the market for ancillary services and it is supposed to solve security of supply problems. Similarly to what happens with CRMs, this approach segments the market for ancillary services. The same concerns expressed above for the segmentation of the CRM can be applied here to the market for ancillary services. Once again, it would be more efficient to introduce specific support schemes for DSR and then let these resources offer the ancillary services tailored to the system needs, and not on the characteristic of a specific technology. Furthermore, if a CRM is in place, the peak-shaving product would clearly interfere with the CRM's operation during scarcity conditions, providing double protection to consumers which likely results in an economic-inefficient outcome.

Research.

Sustainability Analytics: Meeting Carbon Commitments Most Efficiently

By: James Donegan

What makes a sustainable company a sustainable company? More and more companies are setting seemingly ambitious net-zero targets for their greenhouse gas emissions, with the dirty secret being that the path to achieving these targets is largely met with little to no actual emissions reductions from the company itself. These targets are being met through financial instruments, where renewable energy credits are purchased from a renewable energy plant in a different corner of the world and applied against a company's operational emissions to counteract them on paper. So what can be done differently?

We built a prescriptive optimization framework, looking at how a major telecommunications company consumes energy, and output specific and actionable upgrade decisions that have been optimized to both save money and reduce emissions. Applying this framework resulted in a >10% reduction in operational emissions and energy spend. Furthermore, we look beyond operational emissions, and instead at embedded emissions of how a telecommunication network has been designed, and ask questions on what can be done to optimize this architecture. This included investigating the financial and environmental implications of reducing the real estate footprint of the company's telecommunications network, finding billions of dollars of savings in energy spend just in the baseline location of New York City for the company.

There are five main stages of results from this project. Firstly, we examine the output of a baseline optimization model using only the information available from the building energy audits Verizon conducted in its NYC Central Offices which highlights a 12% reduction in energy costs and a 14% reduction in emissions through use of this optimization model.

The second stage of results, examined the effect of bundling network transformation inside-plant work with building upgrades in the optimization model. This highlighted a 14% reduction in energy costs and a 18% reduction in emissions through use of this optimization model.

Thirdly, our final piece of results from the optimization model is to examine the price of carbon set by the city of New York for their incoming environmental compliance laws. Is this the best price to reduce the most amount of emissions? Is this the best price holistically from a sustainability standpoint? In this section, we find the energy gap of Verizon's operations where a 24% reduction in energy costs and a 17% reduction in emissions would be possible and recommended with no carbon tax introduction.

The fourth batch of results is from an investigation into the most sustainable way to achieve net zero. This looks at how scalable the

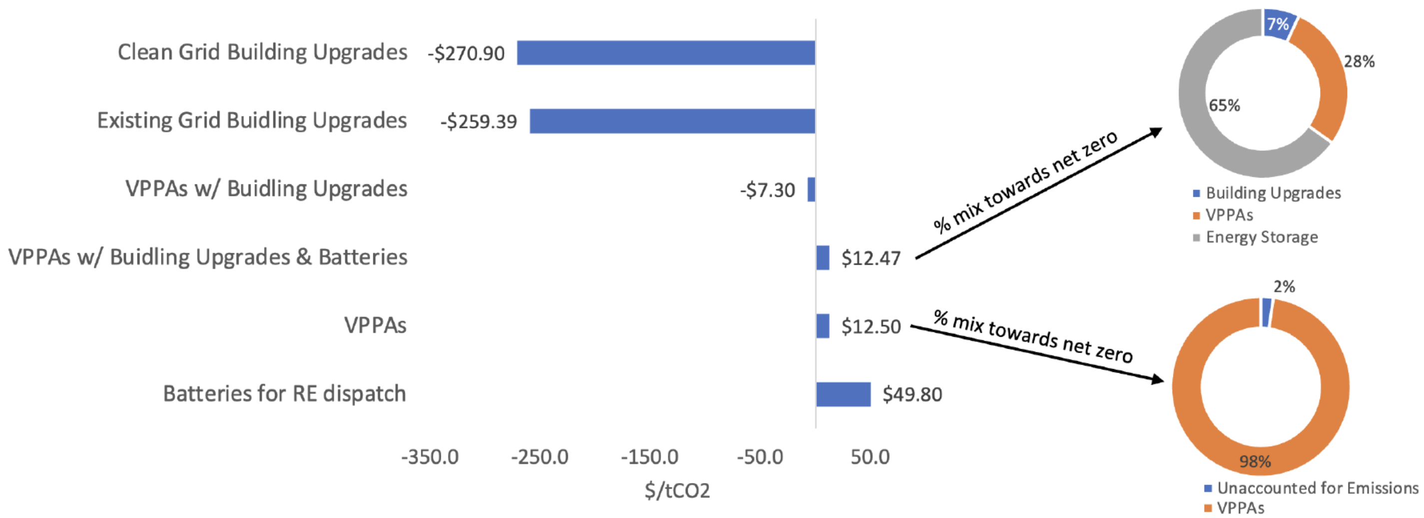

Figure 1. Dollars spent per ton of CO_2 accounted for on Verizon's net zero goal for different solutions or combinations of solutions, including pie charts showing contribution mix towards net zero contribution for identically priced solutions of existing green bond funded VPPAs, or a mixture of building upgrades, on-site energy storage, and green bond funded VPPAs.

building upgrades are nationally, and how much of a dent they would put into the company's total scope 1 & 2 emissions. This section also looks at alternative solutions to meet Verizon's net-zero goals that have a reduction in emissions, to complement both building upgrades and the existing method of financing VPPAs. This section finds that if Verizon's sustainability budget was restructured and distributed to a variety of emissions reductions projects, a 60% reduction in emissions is possible for the same cost per ton of CO_2 that Verizon is currently spending (see Figure above). This solution features a large investment in energy storage which at this point is purely theoretical. As a follow on to this work we would recommend further investigating the opportunity cost of widespread energy storage installations for Verizon. This analysis is intended to show rough possibilities on the energy storage point.

Our final set of results highlighted the financial and sustainability opportunities available from the consolidation of Central Offices in high-population-density metropolitan areas. These opportunities sum to billions of dollars of savings for Verizon, albeit with significant challenges in implementation.

The project produced significant amounts of results which can be condensed to the below major takeaways and recommendations:

- Creating a prescriptive optimization model to recommend building upgrades can not only reduce emissions but can significantly reduce energy expenditure, up to 24%.

- Alternatives to renewable energy credits can be utilized by companies to achieve sustainability goals at the same price, while also reducing operational emissions by up to 60%. This should be the gold standard for sustainability and energy teams at organizations. These are sometimes considered to have high barriers to entry given the operational time and expense associated with building upgrades compared to financial instruments such as VPPAs.

- Analyzing the requirements of modern network architecture can point to significant opportunities in real estate consolidation which not only saves money, but also reduces emissions, and creates a more robust network overall. The barrier for entry to any type of consolidation project however is huge, as the projects would take many years to complete at great upfront cost.

The most important learning from this work is to never stop working towards reducing your carbon footprint; continue to evolve and use the most state-of-theart tools at your disposal to determine the best paths forwards. True corporate sustainability is possible if companies are willing to dive in head first.

James Donegan (2023), "Sustainability Analytics: Meeting Carbon Commitments Most Efficiently", CEEPR WP-2023-15, MIT, September 2023.

John Bistline, Neil Mehrotra, and Catherine Wolfram (2023), "Economic Implications of the Climate Provisions of the Inflation Reduction Act", CEEPR WP-2023-14, MIT, August 2023.



Research.

Economic Implications of the Climate Provisions of the Inflation Reduction Act

By: John Bistline, Neil Mehrotra, and Catherine Wolfram

The Inflation Reduction Act (IRA) represents the largest federal response to climate change to date. The problem IRA confronts is massive — re-orienting the way the U.S. and global economies produce and consume energy. IRA's incentives span the entire energy sector, from producers of raw materials to end-use consumers, and will set considerable new forces in motion.

This paper offers several initial perspectives on what IRA's climate-related provisions could imply for energy transitions and key macroeconomic indicators using detailed energy systems modeling and general equilibrium modeling of the U.S. economy. The paper focuses on several major themes.

The first theme is the fiscal implications of the Act. There is a wide range of uncertainty in the extent to which firms and households will take up the different tax credits. To evaluate the Act's fiscal impacts, the authors summarize evidence from the Electric Power Research Institute's U.S. Regional Economy, Greenhouse Gas, and Energy (EPRI's US-REGEN) model. Analysis using this model suggests that IRA, along with other policies and market trends, shifts baseline expectations of firms, households, and policymakers concerning the pace and extent of future decarbonization. Particularly, under IRA, clean electricity investments span 34–116 gigawatts of nameplate capacity added annually through 2035, compared with 18 GW/year on average in the previous decade and 36 GW/yr in 2021. In addition, IRA is expected to increase the electric vehicle share of new vehicle sales by 12 percentage points in 2030—from 32% without IRA to 44% with IRA credits.

However, the projected pace and extent of these changes depend on assumptions about future policies, technologies, and markets. The uncertainty associated with these projections reflects IRA implementation details and unknown responses to siting and permitting challenges, workforce changes, global supply chain shifts, and non-cost barriers to deployment.

The acceleration in the deployment of clean supply- and demand-side technologies in the paper's modeling implies greater uptake of IRA incentives than initial estimates indicated. These projections indicate that fiscal costs of IRA tax credits for clean electricity, carbon capture, and electric vehicles may be $780B by 2031 in our central case — nearly three times the Congressional Budget Office (CBO) and Joint Committee on Taxation's (JCT) score for comparable credits, thus suggesting that initial estimates of the fiscal costs may be understated.

The paper's second theme is the market impacts of IRA incentives, particularly negative prices in wholesale electricity markets. Electricity generation technologies that collect production-based tax credits will have strong incentives to operate even when wholesale prices are low or even negative to receive IRA credits. Some areas of the country are already seeing negative prices, but their prevalence will likely increase with IRA. These negative prices can alter economic signals for market entry and exit of generators, shift incentives for locational decisions and

balancing resources (e.g., energy storage, transmission), and change the economics of end-use electrification and new loads (e.g., hydrogen production, cryptocurrency mining).

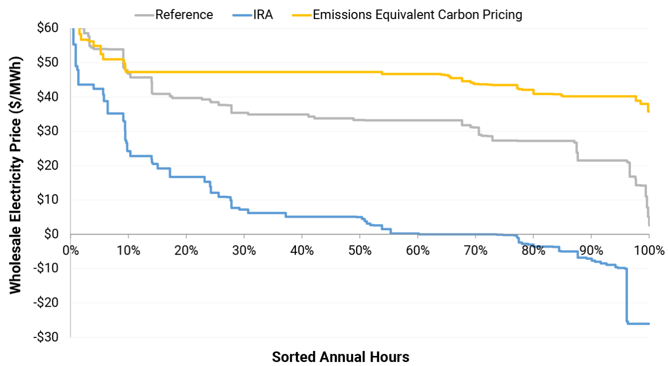

Figure 1: Wholesale electricity price duration curves for the reference, IRA, and carbon price scenarios.

Curves are shown for the Southwest Power Pool (SPP) region in 2050, which includes South Dakota, Nebraska, Kansas, and Oklahoma.

The third theme is the distributional impacts and the possible incidence of the different subsidies in IRA. This paper notes the extent to which IRA may drive down retail prices for energy due to subsidies for electricity generation and investment, reflecting transfers from the federal government (and ultimately taxpayers) to consumers and clean electricity providers. In addition to potentially decreasing retail electricity prices, IRA could lower expenditures on fossil fuels due to its incentives for end-use electrification, especially petroleum for transportation. The authors describe patterns in energy expenditures by income, as well as results from US-REGEN under a counterfactual scenario without IRA subsidies to inform the extent of inframarginal transfers to firms and households that would have adopted these technologies anyway.

The fourth theme is the relationship between IRA and the macroeconomy. To elucidate the potential macroeconomic impacts of IRA, this paper presents a representative agent model of the economy which features subsidized clean energy as an input. The model demonstrates how clean energy subsidies function as a supply-side policy that boosts output, investment, wages, and labor productivity while reducing the price of electricity. These dynamic effects work to partially offset the static fiscal cost of the policy. Along the transition path, increased investment demand raises interest rates and lowers private consumption. Bottlenecks lower real clean energy investment, but may raise investment expenditures and the fiscal cost of the investment tax credit as the relative price of investment in clean energy capital rises. However, the slower pace of investment under bottlenecks mitigates the rise in the real interest rate. Elastic labor supply and learning-by-doing externalities can increase the clean energy capital stock in steady state under a subsidy policy. Even labor and domestic sourcing requirements as structured in IRA would increase the steady state clean energy capital stock. Clean energy investment may crowd out non-energy investment in the short-run but increase non-energy capital in the long run.

The fifth theme is a comparative analysis of the subsidies approach in the IRA to carbon pricing. This paper presents a comparison that is both conceptual and quantitative, using a carbon price that would yield comparable emissions reductions over a similar timeframe. Conceptually, while both policies lower the relative price of clean to fossil fuel power generation, a carbon tax raises energy prices, encouraging energy conservation but carrying negative supply-side implications for output, investment, and wages. The conservation margin means that a carbon tax results in a larger decline in emissions. In the context of the model, despite its positive supply-side effects, optimal climate policy generically involves a positive carbon tax and a zero clean-energy subsidy. Therefore, the case for an approach centered on clean energy subsidies relies heavily on strong learning-by-doing externalities.

The paper describes further dimensions along which carbon taxes and subsidies differ that are not captured in the model, including fuel switching, differential carbon intensity, and impacts from usage along the intensive margin. Subsidies and carbon pricing are also compared in terms of the incentives created for innovation. Within this section, w the economics of some of the industrial policy aspects of IRA, which offers higher tax credits for firms that adopt certain labor practices and buy inputs manufactured in the U.S. is discussed. These provisions may be addressing market failures, but if not, they may raise costs.

The sixth and final theme focuses on quantifying the IRA's possible macroeconomic impacts, using inputs from the US-REGEN model in the Federal Reserve's FRBUS model. The new investment under IRA, while large relative to the current level of investment in the energy sector, is comparatively small as both a share of overall investment and overall economic activity. Increases in clean power investment and transfers to households to subsidize electric vehicles and other household equipment initially increases demand before raising the capital stock and output. The movements in interest rates and unemployment are very small owing to the small size of electric power investment relative to the overall economy. Although this paper finds that IRA investments in the baseline case are likely not large enough to meaningfully influence macroeconomic aggregates, it quantifies how the macroeconomic environment — including higher interest rates and rising costs of labor and materials — could have meaningful negative impacts on clean energy investment.

This paper's review of potential IRA impacts points to several areas for additional research. Notably, assessing interactions between IRA incentives and changes in federal regulations, state policies, and company targets will be important. Future work should also quantify the aggregate macroeconomic impacts of IRA, Infrastructure Investment and Jobs Act, and CHIPS and Science Act, as all three are expected to increase investments across a similar timeframe and have impacts on manufacturing, construction, and raw materials. Finally, understanding the economic incidence of subsidies and the distributional implications of IRA will be valuable to policymakers and other stakeholders, especially since many IRA provisions target energy equity, environmental justice, and disadvantaged communities.

—Summary by Diana Degnan

Brian Deese at the White House in 2021
Credits: Photo courtesy of the White House

News.

MIT Welcomes Brian Deese as Its Next Institute Innovation Fellow

By: MIT Office of the Provost

The former senior advisor to two U.S. presidents will focus on how to advance U.S. industrial strategy and address climate change.

MIT has appointed former White House National Economic Council (NEC) director Brian Deese as an MIT Innovation Fellow, focusing on the impact of economic policies that strengthen the United States' industrial capacity and on accelerating climate investment and innovation. Deese began his appointment earlier this summer.

"From climate change to U.S. industrial strategy, the people of MIT strive to make serious positive change at scale — and in Brian Deese, we have found a brilliant ally, guide, and inspiration," says MIT President Sally Kornbluth. "He pairs an easy command of technological questions with a rare grasp of contemporary policy and the politics it takes for such policies to succeed. We are extremely fortunate to have Brian with us for this pivotal year."

Deese is an accomplished public policy innovator. As President Joe Biden's top economic advisor, he was instrumental in shaping several pieces of legislation — the bipartisan Infrastructure Investment and Jobs Act, the CHIPS and Science Act, and the Inflation Reduction Act — that together are expected to yield more than $3 trillion over the next decade in public and private investments in physical infrastructure, semiconductors, and clean energy, as well as a major expansion of scientific research.

"I was attracted to MIT by its combination of extraordinary capabilities in engineering, science, and economics, and the desire and enthusiasm to translate those capabilities into real-world outcomes," says Deese.

Climate and economic policy expertise

Deese's public service career has spanned multiple periods of global economic crisis. He has helped shape policies ranging from clean energy infrastructure investments to addressing supply chain disruptions triggered by the pandemic and the war in Ukraine.

As NEC director in the Biden White House, Deese oversaw the development of domestic and international economic policy. Previously, he served as the global head of sustainable investing at BlackRock, Inc., one of the world's leading asset management firms; before that, he held several key posts in the Obama White House, serving as the president's top advisor on climate policy; deputy director of the Office of Management and Budget; and deputy director of the NEC. Early in the Obama Administration, Deese played a key role in developing and implementing the rescue of the U.S. auto industry during the Great Recession. Deese earned a bachelor of arts degree from Middlebury College and his JD from Yale Law School.

Despite recent legislative progress, the world still faces daunting climate and energy challenges, including the need to reduce greenhouse gas emissions, increase energy capacity, and fill infrastructure gaps, Deese notes.

"Our biggest challenge is our biggest opportunity," he says. "We need to build at a speed not seen in generations."

Deese is also thinking about how to effectively design and implement industrial strategy approaches that build on recent efforts to restore the U.S. semiconductor industry. What's needed, he says, is an approach that can foster innovation and build manufacturing capacity — especially in economically disadvantaged areas of the country — while learning lessons from previous successes and failures in this field.

"This is a timely and important appointment because Brian has enormous experience at the top levels of government in shaping public policies for climate, technology, manufacturing, and energy, and the consequences for shared prosperity nationally and globally — all subjects of intense interest to the MIT community," says MIT Associate Provost Richard Lester. "I fully expect that faculty and student engagement with Brian while he is with us will help advance MIT research, innovation, and impact in these critical areas."

Innovation fellowship

Previous MIT Innovation Fellows, typically in residence for a year or more, have included luminaries from industry and government, including most recently Virginia M. "Ginny" Rometty, former chair, president, and CEO of IBM; Eric Schmidt, former executive chair of Google's parent company, Alphabet; the late Ash Carter, former U.S. secretary of defense; and former Massachusetts Governor Deval Patrick.

During his time at MIT, Deese will work on a project detailing and mapping investment in renewable energy and other climate technologies. Clean investment is quickly becoming one of the largest industries in the U.S., and public and private investment in decarbonization is key to accelerate the manufacturing and adoption of the technologies needed for clean electricity and transportation, building electrification, low-emission industrial production, and carbon management.

"I hope my role at MIT can largely be about forging partnerships within the Institute and outside of the Institute to significantly reduce the time between innovation and outcomes into the world," says Deese.

Tracking Clean Investment

Previously, however, there was no comprehensive way to monitor investments in clean technology and infrastructure in the U.S., making it difficult to assess on-the-ground progress in the country's transition to a net-zero economy. To close this gap, Deese is working with researchers at the MIT Center for Energy and Environmental Policy Research (CEEPR) and Rhodium Group on a tool that tracks these investment flows, called the Clean Investment Monitor (CIM).

This tool offers near real-time tracking of all public and private investments in the manufacture and deployment of the full spectrum of greenhouse gas emission-reducing technologies in the United States, including relevant input components. For analytical tractability and comparability of investment data over time, the CIM focuses on technology categories that are eligible for grants, loans or loan guarantees under the IRA, the IIJA or the CHIPS and Science Act.

Using this approach, the CIM draws on a database of roughly 20,000 individual facilities, 3 million zero-emissions vehicle (ZEV) registrations, 20 million heat pump sales, and 4.5 million distributed electricity generation or storage installations since 2018. By compiling and analyzing this data in a methodologically consistent manner, the CIM provides valuable insights into investment trends, the effects of federal and state policies, and on-the-ground progress in the U.S. towards net-zero greenhouse gas emissions.

CEEPR Director Christopher Knittel looks forward to the collaboration: "We're excited to host Brian and his work at MIT to track clean investment flows."

Education.

Updates from MIT's CATE Program

By: Aisling O'Grady and Trinity White

The Climate Action Through Education (CATE) Program aims to empower and support teachers as they educate the next generation of climate leaders. The primary goal of this effort has been to develop an interdisciplinary climate curriculum for high school educators. This work has been spearheaded by five incredible educators, who teach Language Arts (Kathryn Teissier du Cros at Newton North High School), History (Michael Kozuch at Newton South High School), Math (Amy Block at the Governor's Academy), and Sciences (Lisa Borgatti at the Governor's Academy and Gary Smith at St. John's Prep). Over the past two years this team has created 24+ labs, lessons, units, and more that can be used in high school classrooms.

In addition to curriculum development, the team hosted its second annual climate professional development workshop for high school teachers in collaboration with the Massachusetts Teachers Union Climate Action Network (MTA CAN) and the Massachusetts chapter of the American Federation of Teachers (AFT), sponsored by the Beker Foundation. The workshop was held exclusively for high school teachers and received over 60 interested applicants across multiple disciplines, with 26 accepted attendees.

As highlighted in the spring CEEPR newsletter, CATE also held its first annual Climate Action and Education Conference in April of this year. This event was a collaboration with Earth Day Boston and MTA CAN, funded by MIT's Climate Nucleus as part of Earth Month at MIT. Attendance surpassed 130 people, including high school students, K-12 teachers, and local organizations.

Next steps: Climate curriculum launch

In Fall of 2023, CATE's interdisciplinary curriculum will launch for free, to any interested educator. These 24+ lessons, labs, and activities have been crafted by our practicing high school teachers with guidance from MIT staff and faculty. In many cases, our team has piloted these lessons in their own classrooms, reaffirming that the curriculum is grounded in typical requirements for core high school classes: History, ELA, Sciences, and Math. In an attempt to fully support teachers, most lessons are accompanied by a Teacher Background Sheet, Student Background Sheet, and full guide with all necessary materials accessible through Google Drive.

The curriculum aims to inform students about the causes and consequences of anthropogenic climate change and to equip them with the knowledge and sense of agency needed to contribute to climate solutions. This set of materials has been vetted by 42 Massachusetts high school teachers in formal feedback sessions, 14 high school teachers through a classroom pilot program, graduate students and postdoctoral associates at MIT, undergraduate and high school students, and our MIT Faculty Review Committee. We have cross-referenced all of these materials with: the Next Generation Science Standards (NGSS); Massachusetts Curriculum Frameworks in History/Social Science, ELA, Math and STE; and the Massachusetts Social and Emotional Learning Competencies (SEL).

Place-based learning (PBL) is another component of the curriculum, attempting to connect students to climate impacts and solutions in their own backyard through local data, etc. This portion of the curriculum is no more than 20% of a given lesson, and is currently specific to Massachusetts. While the curriculum is especially relevant to teachers in MA through alignment with MA standards and PBL elements, it is in no way irrelevant to educators outside of the state. In the future, expansion plans include tailoring these PBL examples to various states and regions of the US and beyond, and to cross-reference the content with standards from each U.S. state.

Each lesson can be used on its own, or alongside others, while blending into teachers' current materials for easy classroom integration. Ideally, the materials can serve as one-to-one replacements for standard lessons in core disciplines – for example, the Gilded Age and Climate Change history unit replacing typical Industrial Revolution material in a 10th grade U.S. History class.

The content also ties into MIT resources like the Today I Learned Climate Podcast Educator Guides, Professor Kerry Emmanuel's Digital Climate Primer, and the MIT Energy Initiative's Future Of Studies. The team is currently exploring connections to CEEPR research, and other climate-related work taking place across MIT.

The curriculum will launch in three phases:

Phase 1
The first phase of the curriculum launch is planned for September 2023, interested educators can email **cateprogram@mit.edu** for access to the curriculum in its first phase via Google Drive. Preliminary data like: name, school, school location, and classes taught will be collected.

Phase 2
CATE is expected to launch its own site at cate.mit.edu in October 2023, whereby interested educators can access the curriculum in its entirety. For data collection purposes, educators will be asked to create a free account and provide the information referenced in Phase 1.

Phase 3
Throughout the 2023-24 academic year, CATE will run a case study program related to the curriculum launch. Educators who use the materials in their classrooms will have the opportunity to receive a stipend in exchange for a one-hour interview. The goal being to improve the materials and better understand how they are being used in actuality. Stipends will be available for a maximum of 100 teachers.

Next steps: MOOC launch

In late Fall of 2023, CATE will launch its first massive open online course (MOOC), titled Climate Connecting Classrooms: Multi-Disciplinary Climate Change Tools for Teachers. This six-week course will be available for any interested educator with internet access, looking to

Pictured: Kathryn Teissier du Cros and Michael Kozuch, CATE Curriculum Developers. *Photo credit: Tony Rinaldo.*

bring climate into their classroom through new methodologies, practices, and tools. The content will span climate basics (beyond the science), climate and environmental justice classroom tools, sustainability and environmental education pedagogy, applications in STEM and social sciences (high school focus), and climate curriculum building.

Participants in this course will learn from MIT resources, research, graduate students and postdocs via the introductory 'climate basics' week. Other lecturers include Elizabeth Potter-Nelson, Faculty at University of Maine at Farmington (UMF), who will instruct the best practices and pedagogy week. As well as, Christopher Rabe, a postdoctoral associate at MIT's Environmental Solutions Initiative (ESI), who covers tools and practices to bring climate and environmental justice into the classroom. The following weeks will be led by the team of CATE teachers, with content from Professor Christopher R. Knittel.

This course will be moderated live for the full six-weeks of its first run later this year. Interested learners can take the class for free via edX, or opt for a verified MIT certificate for a small fee. For further information on the offerings and launch dates, contact Aisling O'Grady at **aogrady@mit.edu**.

CATE wins MIT's Jameel World Education Lab (JWEL) grant to develop and test an innovative way to improve climate education

The JWEL 2023 Education Innovation Grant awarded one of eleven grants to the CATE program to develop a toolkit focused on impactful, student-centered climate education. The project is titled Design Thinking for Climate Toolkit.

This effort addresses opportunities to:

- Empower high school students and teachers with leading sustainability education methodologies and MIT climate resources to engage with local climate issues and explore pathways to solutions
- Employ design thinking (DT) and inquiry-based learning (IBL) processes with MIT undergrads to develop feasible, localized climate action plans
- Help close knowledge gaps between academia and high school communities

The Toolkit is a three-stage plan that intends to support climate education and global youth engagement in climate solutions.

Stage 1
The first part of this project is the in-progress creation of Professional Development materials for a global audience of high school teachers, focused on Design Thinking and Inquiry-Based Learning as methodologies for tackling localized climate issues.

Stage 2
The second stage involves relationships with a select group of global educators who will apply materials from stage 1 in their classrooms. To further their work and commitment to climate education, the Toolkit will provide stipends and support. CATE is exploring partnerships in Belize, Chile, Brazil, and Sweden to ensure this project has a global impact.

Stage 3
Lastly, phase 3 involves an undergraduate spring 2024 course titled Using Design Thinking to Tackle Localized Climate Impacts. This course will be co-taught by CEEPR Director and Sloan Professor Christopher R. Knittel and MITEI Director of Education Antje Danielson, and inspired by materials from stage 1 and previous MITEI Education efforts. Through this course students will apply design thinking methodology to local climate issues and engage with stakeholders while applying pedagogical community engagement tools. Related course topics will include: using projection models to assess climate impacts, climate action plans, anthropogenic climate change, the energy transition, and energy systems broadly. Some students will be connected to problems identified in Stage 2.

This project will close at the end of June 2024, but all related materials will be available for free via Creative Commons licensing through J-WEL and CATE.

Personnel.

Introducing CEEPR's New Researchers in 2023

In addition to **Brian Deese** joining CEEPR as an MIT Innovation Fellow (featured earlier in this newsletter), we are pleased to welcome these new colleagues to our group as we start a new academic year at MIT:

Catherine D. Wolfram
William F. Pounds Professor of Energy Economics

Catherine Wolfram joins the MIT Sloan School of Management as the William F. Pounds Professor of Energy Economics and as a CEEPR Faculty Affiliate. She previously served as the Cora Jane Flood Professor of Business Administration at the Haas School of Business at UC Berkeley.

From March 2021 to October 2022, she served as the Deputy Assistant Secretary for Climate and Energy Economics at the U.S. Treasury, while on leave from UC Berkeley.

Before leaving for government service, she was the Program Director of the National Bureau of Economic Research's Environment and Energy Economics Program and a research affiliate at the Energy Institute at Haas. Before joining the faculty at UC Berkeley, she was an Assistant Professor of Economics at Harvard.

Wolfram has published extensively on the economics of energy markets. Her work has analyzed rural electrification programs in the developing world, energy efficiency programs in the US, the effects of environmental regulation on energy markets and the impact of privatization and restructuring in the US and UK. She is currently working on several projects at the intersection of climate and trade. She received a Ph.D. in Economics from MIT and an A.B. from Harvard.

Leandra English
Senior Advisor

Leandra English has been appointed Senior Advisor at MIT, working alongside Brian Deese on the Clean Investment Monitor project. She most recently served as the Special Assistant to the President and Chief of Staff for the National Economic Council since her appointment in 2021.

Prior to her most recent stint in federal service, Leandra was the Director of Policy for the New York State Department of Financial Services where she managed the department's portfolio of policy initiatives involving consumers, financial services, and other issues. Prior to joining DFS, she served in a variety of roles at the Consumer Financial Protection Bureau including Acting Director, Chief of Staff, and Deputy Chief Operating Officer. In addition, Leandra held senior roles at the U.S. Office of Management and Budget (OMB) and the U.S. Office of Personnel Management (OPM). English also previously served as Director of Financial Services Advocacy for the Consumer Federation of America (CFA) in Washington D.C. She received her B.A. from New York University and a M.S. from the London School of Economics.

Lily Bermel, *Research Associate*

Lily Bermel works with MIT Innovation Fellow Brian Deese on a range of climate change and industrial policy projects, including the Clean Investment Monitor. Before joining MIT, Lily served as a policy advisor for three years on the U.S. State Department climate team, led by Special Presidential Envoy for Climate John Kerry. There, she negotiated on behalf of the United States under the UN Framework Convention on Climate Change, the Paris Agreement, and other multilateral fora; led diplomatic and private sector engagement on nitrous oxide; strengthened capacity literacy in the Foreign Service, including by developing data tools; advanced implementation of the Global Methane Pledge; shaped the first public-private "green trade mission" to Egypt; and coordinated many other efforts to raise global climate ambition. Previously, Lily wrote a series of policy proposals for the Kingdom of Tonga, developed the sustainability department at Cornell Dining, and contributed to climate policy in Massachusetts at the state and local levels. Lily received a B.S. in Environment and Sustainability from Cornell University.

Stephen Lee, *Postdoctoral Associate*

Stephen's research focuses on the development of geospatial machine learning systems that produce high-resolution maps of electricity and heating demand in the US and across the globe. He specifically combines deep learning and Bayesian inference methods to build novel systems for multimodal data fusion capable of encoding constraints from physics- and economics-based theory. Stephen received a Ph.D. and S.M. in Electrical Engineering and Computer Science from MIT, an S.M. in Technology and Policy from MIT, and a B.S. in Materials Science and Engineering with a second major in Economics from Johns Hopkins University.

Juan Senga, *Postdoctoral Associate*

Juan's work focuses on quantitative modeling and economic analysis of projects related to the energy transition. Currently, he is looking into the modeling of long-range electricity transmission in the US with the goal of increasing capacity at the least cost. Before joining CEEPR, Juan was a postdoctoral fellow at Nanyang Technological University, Singapore. There, he designed optimization algorithms for large-scale manufacturing and remanufacturing operations and humanitarian supply chains. He also worked on electricity forecasting models for Singapore, alternative land-use policy for palm oil plantations in Malaysia, and evaluating the viability of agrivoltaics business models. He obtained a Ph.D. in Operations Management from Nanyang Business School and a B.S. from Ateneo de Manila University, Philippines.

Shen Wang, *Postdoctoral Associate*

Shen Wang is a Postdoctoral Associate at the MIT Center for Energy & Environmental Policy Research. His research foci include power resource planning, electricity market design, and the environmental and energy policies associated with the energy transition. At CEEPR, Shen investigates the role of the hydropower of Quebec in the context of decarbonization and climate change, which aims to identify innovative strategies for optimizing hydro resources and enhancing their efficiency and participation across various electricity markets in Northeastern North America. Before joining CEEPR, Shen completed his Ph.D. in Energy Economics & Management at Johns Hopkins University, where he also received M.S. in Applied Mathematics and M.S.E. in Environmental & Health Engineering.

Personnel.

Chris Colcord, *Graduate Research Assistant*

Chris Colcord's current research focuses on the role of industrial policy in decarbonization of the iron and steel industries in the United States. Chris is pursuing an M.S. in Technology and Policy at MIT. Prior to joining MIT, Chris worked for three years as an MEP engineering consultant, building energy models and designing high-efficiency heat pump systems for residences and commercial buildings. Chris holds a bachelor's degree in mechanical engineering from Tufts University.

Daria Ekimova, *MIT Visiting Student*

Daria Ekimova has a background in Economics, and her current studies at the Technical University of Munich are focused on Energy Markets and Power Engineering. She has experience working at a grid-scale battery optimization company, where she previously evaluated European energy market regulations and their accessibility for implementing more storage into the grid. Before joining CEEPR, she worked with an energy consulting company to develop a long-term power portfolio optimization model with exchange-traded derivatives. She is excited about applying interdisciplinary methods from operations research, finance, and engineering to solve the urgent problems of energy system participants.

Khyati Garg, *Graduate Research Assistant*

Khyati Garg is an S.M. candidate in the Technology and Policy Program at MIT. Her background is in climate mitigation technologies and she is interested in how technologies can be commercialized with the aid of a strong policy framework. She recently completed her undergraduate degree in chemical engineering from UC Berkeley. Khyati's current project with Christopher Knittel, Brian Deese, and Leandra English is centered on tracking renewable investments stimulated by climate legislation under the Biden Administration. She hopes to learn how the Inflation Reduction Act and the bipartisan InfrastructureInvestment and Jobs Act incentivize different climate technologies and therefore impact state energy portfolios.

Luke Heeney, *Graduate Research Assistant*

Luke is passionate about using economics and statistics to bring about a just transition to net zero. He is currently completing an M.S. in Technology and Policy at MIT and holds a Bachelor of Advanced Finance and Economics (Hons I) from the University of Queensland. Before joining MIT, Luke was an Associate in Boston Consulting Group's energy and climate teams, completing strategy projects for public and private clients, including a COP Presidency. He has also worked on climate finance with Oxford's Smith School for Enterprise and the Environment, and on Australian energy and climate policy for various think tanks.

Peter Heller, *Graduate Research Assistant*

Peter is an S.M. candidate in the Technology and Policy Program at MIT. His research is focused on ensuring a financially sustainable, just, and inclusive energy transition. He is particularly interested in regulation of the electricity sector and innovative policies to protect low-income families during the renewable transition. He is also an associate at the Colorado Energy and Water Institute, where he coordinates Western states' efforts in creating a wholesale electricity market. Prior to MIT, Peter worked as Colorado State Senator Chris Hansen's policy director, focused on energy and environmental legislation. Peter holds a B.S. in environmental engineering from the University of Colorado Boulder.

Aleksander Ahmet Kavur, *MIT Visiting Student*

Aleksander Ahmet Kavur is an MIT Visiting Student at CEEPR. His research focuses on the current and future costing of novel energy technologies and systems. He participates in the Integrated Floating Maritime Nuclear System for Hydrogen and Ammonia Production Project. Before coming to CEEPR, Ahmet was a graduate student majoring in Environmental Systems Policy and minoring in Renewable Energy at ETH Zurich, and an investment manager at a family office, focusing on carbon markets and battery storage investments. He also has experience in the energy project development and construction industries.

Demis Legrenzi, *MIT Visiting Student*

Demis Legrenzi conducts his research mainly on Agent Based Models (ABM) applied to complex macroeconomic and financial environments, as well as circular economy, and consumer preferences in terms of green behavior. This approach pursues the evaluation of policy solutions and the exploration of future development scenarios. He is also interested in decarbonization strategies and policies. Demis received his M.Sc. (cum laude) at the University of Brescia, where he is currently Ph.D. candidate, while cooperating with Fondazione Eni Enrico Mattei (FEEM).

Abigail Randall, *Graduate Research Assistant*

Abigail is a second year Technology and Policy Program master's student at MIT. She works as a Research Assistant between the Olivetti Group, the Material Systems Laboratory, and CEEPR to analyze the supply chains of critical minerals for the energy transition. She is passionate about the policy implications of the renewable energy transition, and how this impacts demand for critical mineral mining. For her undergraduate studies, she attended the University of Michigan with Highest Honors, where she conducted research on energy policy in the Great Lakes region as well as research on local government attitudes towards wind and solar development in Michigan. Before coming to MIT, she managed federally funded research projects on solar energy soft cost reductions as a Science and Technology Policy Fellow at the U.S. Department of Energy.

Events.

Recent and Upcoming Conferences:

2023 EPRG & CEEPR European 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.

Spring 2024 CEEPR Research Workshop

May 16-17, 2024
Royal Sonesta Boston
Cambridge, Massachusetts

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

Publications.

Recent Working Papers:

WP-2023-16
Improving Predictability of Wind Power Generation
Vivienne Zhang, September 2023

WP-2023-15
Sustainability Analytics: Meeting Carbon Commitments Most Efficiently
James Donegan, September 2023

WP-2023-14
Economic Implications of the Climate Provisions of the Inflation Reduction Act
John Bistline, Neil Mehrotra, and Catherine Wolfram, August 2023

WP-2023-13
Another Source of Inequity? How Grid Reinforcement Costs Differ by the Income of EV User Groups
Sarah A. Steinbach and Maximilian J. Blaschke, July 2023

RC-2023-04
Research Commentary: Comments on Draft Revisions to OMB Circulars A-4 and A-94
Paul Joskow, Christopher Knittel, Deborah Lucas, Gilbert Metcalf, John Parsons, Robert Pindyck, and Richard Schmalensee, July 2023

WP-2023-12
Cost-Efficient Pathways to Decarbonizing Portland Cement Production
Gunther Glenk, Anton Kelnhofer, Rebecca Meier, and Stefan Reichelstein, July 2023

WP-2023-11
Climate Impacts of Bitcoin Mining in the U.S.
Christian Stoll, Lena Klaaßen, Ulrich Gallersdörfer, and Alexander Neumüller, June 2023

RC-2023-03
Research Commentary: The EU Commission's Proposal for Improving the Electricity Market Design: Treading Water, But Not Drowning
Carlos Batlle, Tim Schittekatte, Paolo Mastropietro, and Pablo Rodilla, May 2023

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

ceepr.link/workingpapers

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Photo: CEEPR Director Christopher Knittel giving closing remarks at the 2023 European Energy Policy Conference in Brussels, Belgium on Sept 8, 2023.

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