A HOOVER INSTITUTION ESSAY

Transformation of the American Electric Grid

THE UNMET AGENDA

DAVID VICTOR WITH DAVID FEDOR AND ROB BUECHLER

Energy and Climate

Abstract

The design and operation of the electric power system is on the cusp of massive transformation as policy makers aim to make deep cuts in emissions of global warming pollution and address other challenges. In many respects, the industry and its regulators are well on track in their response. But, on a few critical topics, failure to adopt a new course would harm American interests. This essay, a contribution to the George P. Shultz Task Force on Energy and Climate at the Hoover Institution, identifies the three most important elements of that unmet agenda—critical challenges that are not plausibly on track for effective solutions. They are: 1) planning for reliability and for resilience in a world where grids will operate in novel ways; 2) building transmission lines and interconnections in places of greatest value; and 3) reshaping the methods by which the public sector and electric power industry furthers new ideas through demonstration and innovation.

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In the year 2000, the National Academy of Engineering looked back on the last century to identify the single most important technological innovation. Their answer was electricity.[1] Over the century, electric service went from a niche product that served highly specialized industrial needs and a few wealthy customers to a ubiquitous presence. Economic historians have pointed to electricity as the single most important innovation driving expansion of economic opportunity over the last century.[2]

Today, there is a lot of talk of complete transformation in the ways that electric power is provided. In the extreme, some analysts even ponder whether a grid will be needed at all. It is easy, however, to overstate the profundity of change. The reality is that most practical futures for the electric power system involve, as today, a power system that depends centrally on the grid.[3] The grid is likely to remain central, but there will be many shifts in investment and grid operations as society expects more and different things from electric power service:

Deep decarbonization through electrification. Nearly every credible study of deep emission cuts shows that the role of electric power will expand, possibly radically. Indeed, most studies point, roughly, to a doubling in the volume of electrons that will be needed and roughly a doubling in the size of the grid, along with a greatly expanded role for grid services such as electricity storage.[4] This implies the need for investment in new zero-emission generators and more transmission, along with more capable and adaptive distribution systems—and complementary market reforms. Without proper planning, this shift could be jarring for an industry and its regulators, who have been accustomed to planning and investment for a grid where growth in demand has been flat or modest.

A shift to renewables. Not only are there large new needs for electric service, but the types of power supplies are shifting toward a greater role for renewables generation, with zero short-run marginal cost and highly variable output. There are roles, as well, for ongoing use of zero-emission nuclear power plants along with varied new designs for nuclear reactors. And there are expanding opportunities for other types of low-emission power plants, such as those outfitted (or retrofitted) with carbon capture and storage (CCS) systems and new plants that burn clean hydrogen. All that said, many policy discussions about decarbonization treat the big shift toward clean energy supply as synonymous with a shift to intermittent renewables; the recently passed Inflation Reduction Act of 2022 (IRA) energy and climate legislation can be expected to accelerate that through a ten-year extension of renewables tax incentives.[5] As a result, there is increased focus by grid operators, utilities, and regulators on planning scenarios and operational strategies that anticipate much greater supply of intermittent power supplies on the grid. Amid continued production and investment tax credits, commercial-scale non-hydro renewables reached 13.8 percent of US electricity generation in 2021, up from 12.4 percent the year before.[6] This pattern in the United States is part of a global shift to renewables that is continuing apace, despite growing concerns about supply-chain troubles and, possibly temporary, increases in costs.[7]

Resiliency. There is growing awareness of the need for a resilient electric power system—a grid that is reliable, along with resources that can help restore grid services quickly and ride through those interruptions. Interruptions due to inclement weather remain commonplace, and extreme interruptions can cause massive economic harm. Added to those concerns are growing fears of hostile attack—physical and cyber—that may rise in risk with shifts to more internet-connected devices and greater awareness among state- and terrorist-linked organizations about the potential for actions against the grid.[8] There's a lot of good news in how the electric power system is being organized, and one place of progress is industrywide coordination with the national security system to manage cyber threats to the grid.

This list of new expectations for the electric power system is well known. Extensive studies done by industry, regulators, policy and academic analysts, and environmental groups reach similar conclusions, although the details on all those lists always vary a bit.[9]

With experience from diverse backgrounds, members of this work group have been observing the power industry and its policy processes closely for decades. We are, for the most part, impressed by how the industry, its policy makers and regulators, and other stakeholders have become aware of these key agenda items and are responsive. As with nearly every aspect of the American power system, there are large variations across regions, since the industry is organized (and regulated) in such different ways and the resources also vary regionally. A lot of change is under way in an industry that, at least traditionally, has relied on stability to encourage investment in and reliable delivery of its product: electricity. Meanwhile, the electric grid must continue to perform in ways that have become central to modern economies—with high affordability, ubiquitous access, and high reliability.

This report summarizes our observations about where the ecosystem of industry, policy, and stakeholders *is not responding adequately*. Our interest is where the many road-mapping, policy reform, and investment efforts will not, on their own, deliver solutions that are adequate. Put differently, **we are concerned about the unmet agenda**. And rather than a long list of challenges—a list so lengthy and complex that it is hard to set priorities—we focus on the three challenges that we see as most central.

Planning for Reliability and Resilience

Our central concern is reliability. Already today—with only parts of the US electric grid shifting strongly to renewables and with tiny shares for new electric loads such as electric vehicles—it is clear that traditional standards and approaches to measuring and planning for reliability must be reformed. Yet the best new approaches remain unknown. A challenge, whose solutions remain elusive, is to identify new arrays of reliability metrics that reflect changing conditions of the grid without lowering overall reliability of grid service.[10] Currently, most grid planning is done with an eye to peak demand conditions—typically in the winter or the summer, depending on the region—but that might need to shift to look more closely at other times of the year and extreme peak demands in the context of variable supply and other grid conditions. Currently, most grid planning has little empirical basis for estimating variability in new demands for power—such as from electric vehicles connected to the grid—because there is practically no operational experience and little relevant experimental research that can characterize how these new loads may behave.[11]

That standards and strategies for addressing reliability are lagging behind reality is a well-documented concern, but the solutions have remained elusive.[12] The most profound problems of lagging strategies are caused by the rapid shift to generators with zero short-run marginal cost and variable output. Distinct approaches will be needed for *long-term planning* of grids that have large amounts of renewables and possibly more responsive demand, and the short-term future operation of those grids. While the two tasks are related—planning implicates operations, and operational needs define requirements for planning—they are distinct, and efforts on both fronts lag.

Standard metrics for reliability, such as those developed through the North American Electric Reliability Corporation (NERC) and the industry, are misaligned with these new realities of power supply. Concepts such as “generation adequacy” were easier to apply in a world of fossil generators, where the reliability of output and grid configuration were relatively easy to characterize. But they are harder to apply in a world of variable renewable generators, where output and configuration are more stochastic—and the stochasticity not well understood—and where extreme (“tail”) events are more common.[13] The control of supply and demand become more important, even as both may become harder to predict and manage. Where these uncertainties have been acknowledged, efforts to address them are much further advanced on the matter of variable supply than responsive demand. The shape of demand curves and the responsiveness of power demand to new market incentives and technologies could be an even bigger surprise through pervasive electrification than the many surprises that are easier to fathom with intermittent supply.[14]

Standard modeling approaches that have attempted to simulate reliability have nearly always been based on characterizing output from wind, solar, and other variable generators and on viewing performance of the grid by looking backward at history—to past variability in the weather and other extreme events. Similarly, demand forecasting tends to look at historical trends and assume that future loads will have similar characteristics (e.g., flexibility and responsiveness to grid conditions) as in the past. With more tail risks, including from the physical risks of climate change, new forward-looking methods will be needed.[15] So far, however, there hasn’t been enough research into linking forward-looking climate models to the modeling tools and spatial resolution needed for grid planning.[16]

Absent alternatives—which NERC, the Federal Energy Regulatory Commission (FERC), and state regulators could explore but have not, for the most part—the right approach for reliability planning remains unclear. This problem is particularly acute for long-term investments, since shifts in grid configuration are likely to be greatest the further one looks into the future. Litigated regulatory proceedings and precedent tend to value what’s known and well documented at the expense of investments around future trends, novel occurrences, and other needs that might be more uncertain yet better aligned with future requirements. In this vacuum, various regional reliability coordinators—such as the California Independent System Operator (CAISO) and the Electric Reliability Council of Texas—by default become the ones to do this sort of systems-level adequacy planning and guidance on reliability. But these regional perspectives are inadequate. And, unlike in other countries where reliability coordinators are combined with siting and investment authority, in most of the United States, the institutions that are on the front lines of assuring reliability aren’t in the position to implement their findings directly, because they don’t have the direct authority to build what they think is needed.[17]

This problem of reliability planning interacts, of course, with market design. In parts of the country that have moved most rapidly to renewables and are also engaged in the most reorganization of regulatory and market functions, the problem of reliability planning seems to have loomed the largest. Here, the unmet agenda is well understood yet remains without robust solutions. So far, none of the "solutions" to novel market design has proved durable enough to keep the lights on reliably and to send adequate signals for the level and types of long-term investment needed. A variety of novel capacity markets and resource adequacy rules have been implemented, but it isn't clear which of these work best nor which will remain durable under conditions of grid or economic stress. Absent clear guidance on grid value—anchored in new metrics—it will be impossible to design durable market reforms that focus revenues on the projects that generate the greatest value to the grid. And while there is a lot of attention paid to how these issues affect generation and transmission, they also apply to demand. Indeed, with a big shift to electric vehicles (EVs), the nation is plausibly on the cusp of its largest shift in history to responsive demand—if we can figure out the right way to link EV charging incentives to the value that variable charging offers to the grid.

We see solutions to these problems through efforts on five fronts.

First, **the nation needs to invest in a new generation of models and reliability planning tools**. Major elements are already in place with the Grid Modernization Initiative of the US Department of Energy (DOE)—an effort that is engaging the national labs and academics in grid reliability modeling.[18] In tandem, the Advanced Research Projects Agency–Energy (ARPA-E) and others have been investing in new open-source power flow modeling tools.[19] And an array of consultants using industry-standard power flow models, such as PLEXOS, are also doing studies on grid reliability with high penetrations of renewables.[20] What's missing in all this is a tighter connection between this format of academic-style activity and the real-world processes of considering and evaluating possible new reliability metrics and standards that could guide the industry, such as those adopted by NERC. The industry is fundamentally a conservative one—absent new metrics, it is safer to use the old ones, even when the old ones are becoming obsolete.

As the grid evolves toward new structures with more variability in supply and possibly much greater variability in demand a fundamental question remains unanswered: **Do reliability standards need to change, or will variants of older, existing standards suffice when applied using modern grid simulation and planning tools? We urge NERC—working with DOE, FERC, and the National Association of Regulatory Utility Commissioners (NARUC)—to develop and apply a program to answer this fundamental question**. The right answers are probably unknowable without field experimentation and learning, since the reconfiguration of grids will be so profound—with differences across regions—that model-based studies alone will be insufficient. We note that today, NERC is engaged in some reforms to its reliability standards, but principally through activities aimed at getting stakeholder buy-in to new standards, the traditional NERC approach. Something new is needed to develop new standards that are more uncomfortable—and less likely to yield immediate buy-in—even though they are more relevant for the grid of the future.

Understanding the uncertainties better is essential for investment planning and operations. Where uncertainties remain large, there will be greater needs for redundancy—and thus greater investment costs. This maxim about uncertainties applies not just to generation but also, increasingly, the distribution system. With more generation being connected to distribution, and with demand management becoming another tool in managing "generation adequacy," the data needed to characterize uncertainty on the distribution side has become important. This data is potentially much larger than the data sets that have been traditionally used only from the bulk power system.

Second, **in most of the country, planning systems need to adopt longer time horizons**. In many states where integrated resource plans (IRPs) are used for multiyear investment planning, horizons rarely extend beyond a decade, if that. There are some notable exceptions, of course, such as municipalities and utilities that have engaged in long-term decarbonization planning.[21] All told, perhaps only one-fifth of the nation's electric supply is in regions where planning processes look beyond a decade.[22] While there can be substantial value in experimentation across the diverse systems of regulation and business models that exist in the United States, realizing that value will be difficult without more of the country looking further into the future, using tools that make it possible to compare local strategies and experiments with those in other parts of the nation.

Extending time horizons creates a lot of discomfort for regulators and the industry, of course, because it adds many new elements of uncertainty in electric system planning; grappling with that uncertainty and designing standards that can be adapted to new conditions that are unknowable today is intrinsic to the grid transformation that will occur. Long time horizons—along with processes that account for inevitably changing circumstances and other uncertainties—are essential, because mass integration of renewables with high reliability will require investments and programs that require long lead times and investment, planning, and asset commitments. Some of the most profound changes in the grid require the ability to look far into the future at zero-emission systems and the kinds of technologies—such as hydrogen, novel geothermal systems, and other clean-energy dispatchable generators—that are unfamiliar today yet could play vital roles in assuring reliability in the future.[23]

Longer planning horizons won't solve the problems created by lack of appropriate reliability standards (our first effort can help on that front). And they won't solve the problem of divided authority in many regional and state grids (that problem may be unsolvable in the foreseeable future, for it is anchored in state politics). But it will make it easier to identify critical priorities so that disparate regulators, investors, and other stakeholders can focus on solutions.

Third, **we need to tap into the information that can be learned from a large number of experiments now under way across the nation as different jurisdictions grapple with grid reliability**. Many jurisdictions are deploying batteries on their networks; some are adopting programs to encourage variable EV charging. Most are learning how to integrate renewables on their grids in ways that alter the operations of existing fossil and nuclear power plants. Many jurisdictions are running these experiments while also grappling with new social and political priorities for electric service, such as integrating local community concerns like pollution or jobs impacts into siting and operations of the grid infrastructure.[24] Indeed, it may be helpful to think of the grid system, really, as two intertwined networks. One is the physical grid that delivers electrons. The other network is the system of signals and controls—including market prices and expectations—that exchange information between suppliers, users, and operators. Innovation in both technology and business models has been particularly intense in the latter, made possible by new devices being installed on the former. These innovations in signals and controls enable a possibly much more responsive power supply and demand. Because that innovation is itself changing the operation of the grid—and arises in a context when so many other changes are under way—it is impractical to know which innovations are important and scalable without field experimentation.

In effect, the decentralized and often fragmented nature of the American grid planning and regulatory system for the electric industry is a giant learning machine. Properly organized, these experiments can help the nation identify the best solutions to grid reliability—including the identification of possible new approaches to setting and implementing standards.[25] For the most part, however, this machine is not organized for effective learning about these tasks, because so many of them are novel and bespoke to each local grid and political configuration. We see a much bigger role—led, probably, by NARUC—to organize this learning much more systematically. In other areas, NARUC does this well. For all of NARUC's strengths, there is significant turnover in public utility commissioner membership and senior NARUC regulatory leadership. **An active and effective learning process will require a more permanent and adequately funded arrangement that links together state, regional, and federal governing systems that are often connected but do not routinely share information and experience**. This could be advanced through regional groups of public utilities commissions (PUCs)—because regions often have similar challenges—such as the New England Conference of Public Utilities Commissioners (NECPUC), the Committee on Regional Electric Power Cooperation (CREPC, part of the Western Interstate Energy Board and the Western Conference of Public Service Commissioners), and the regional NARUC organizations. There could also be a role for the National Association of State Energy Officials (NASEO), an organization that links the governor-appointed state energy offices, which often are recipients of DOE funding and produce analyses that require regulatory commission or utility implementation.

Applied to grid reliability, this active learning approach would involve setting goals and priorities (in consultation with NERC, FERC, DOE, the Electric Power Research Institute [EPRI], and the industry) and then running an active review program so that the industry and its regulators can learn about the frontier experiences more rapidly. This program of experimentation and learning probably won't advance adequately without a special funding window offered by DOE, although some states, such as New York, appear poised to have active state programs on their own.

This learning approach, focused on the states and other regulators such as FERC, has many advantages—it is the only practical way to learn, under real-world conditions, how new technologies and approaches to grid governance actually work. It must advance in a way that strikes a balance between the need for innovation and creativity and administrative procedure. Innovation intrinsically involves departures from the status quo. The Administrative Procedure Act (APA; and APA-like mindsets) is, by design, a mechanism to slow change so that diverse interests can be alerted and consulted. To some, the APA is a major impediment to creativity and innovation in rate making and regulations, both in the states and at FERC. Regulators have found themselves highly constrained in their ability to be proactive on the grid because the APA (and APA-like mindsets and procedures) cause much of regulation to be reactive, inhospitable to innovation, and anchored in doing legal adjudication. The voices of incumbents and the status quo tend to be better organized and documented and thus influential in litigation-like contexts, whereas the voice of the new and unknown, intrinsically, can't speak so clearly. To others, there is no plausible future in public interest regulation without APA-like mechanisms of notice and response. Mechanisms for reducing this tension don't implicate removing notice and consumer input but do require more explicitly experimental approaches to rule making—those that recognize irreducible uncertainties at the outset; that identify places where investments needed to learn involve higher risks than standard rate-based rule making; and that address upfront financial responsibilities if forecasted benefits do not materialize. This learning process will need to identify experiments and experiences that could be highly valuable yet have not been attempted—and put a spotlight on gaining those experiences.

Fourth, **as the tools for stress testing and reliability planning for the grid are developed some effort is needed to apply them not just to electricity but also to other interconnected infrastructures. The most salient infrastructure interfaces today are between the power grid and the natural gas system**. Failures in that kind of cross-infrastructure planning—imagination, really—were on display with the Texas polar vortex of February 2021, where correlated problems in gas and electricity networks made each network perform more poorly, with catastrophic consequences.[26] Additionally, damages to gas infrastructure in the Boulder County wildfires of December 2021 caused periodic electricity outages to maintain gas system stability; this represents another example of risks propagating through interconnected networks.[27]

In some parts of the country, such as the Southeast, the challenges in expanding the gas pipeline system poses a greater challenge to electric system reliability than the challenges of expanding electric transmission (the subject of the next section). Here, investment planning and growing uncertainty around siting of gas infrastructure—notably long-distance interstate gas pipelines—has become a major factor in grid reliability planning. In other parts of the country, such as in the West and some of the Northeast, there is growing pressure not to invest even in renewal of the existing gas network as policy makers look beyond conventional natural gas. While there are many studies about the “beyond,” there remain many practical questions, such as whether alternatives to gas will use some or all of the existing gas network, rights of way, or other assets, or whether wholly new (or even nongaseous systems) will be needed. Reliability planning for electric networks must take a more explicit network-of-networks approach.

Today, in many parts of the country, gas plants provide a vital source of reliability for the grid, yet the gas–electric infrastructures are not assessed, typically, for their synergistic impacts on system reliability.[28] In the future, as some jurisdictions move away from natural gas, the network of gas pipelines, which represents a huge asset, may be repurposed, such as retrofitting for hydrogen or with large supplies of low carbon synthetic natural gas. Today, we know little about how reliably (or not) that system may operate, let alone how a hydrogen grid system would interface with and affect power grid reliability. Still, other infrastructure interconnections may also prove important, such as new infrastructures needed for carbon management at hundreds of metric tons of CO_2 per year—a task that will require networks of CO_2 pipelines and sequestration sites whose operations may also affect reliability of electric generators and thus the electric grid. All these infrastructures and their seamless transition to new revolutionary futures can be imagined in models and on paper—and climate policies and goals already announced today, in fact, implicitly require development of such systems—but need planning and stress testing for reliability.[29]

Fifth, even as the grid remains indispensable to modern society, there is growing awareness of the bigger picture—the need for resilience so that energy services can continue and behavior be adjusted when conventional grid supply falters.

While there is much more talk about resilience these days, the practical implications for policy and investment processes are still elusive. One of the implications concerns valuation—the need for a better understanding, especially of the costs to the broader society of large-scale and long-duration power outages. Those kinds of extreme events can yield large social costs—as observed in Texas in February 2021. For the most part, there’s a lot of data on frequent, short-term, and isolated outages and, in much of the country, incentives for private actors in the power system to make decisions that value those isolated and short-term costs. But events like those in Texas are a reminder that private incentives for reliability can diverge sharply from broader public needs. Part of realizing incentives is recognizing the importance of resilience as the ability to recover from events that create outages. After storms, for example, much restoration hinges on distribution services and is aided by faster damage assessment and repairs that require more and efficient crew deployment. Redundancy in these areas is costly, and finding the right level of investment requires looking at the societal gains from resilience.

Another implication of resilience thinking is attention to the potential value (or, on the other hand, increased costs) of siting disaggregated generation and demand resources locally. A utility in Colorado, for example, has sited solar panels closer to load (even though such projects were more costly than larger, more distant, solar fields) because of the value of local supplies to resilience planning.[30] Similar siting decisions have occurred at large power users such as in Texas and among remote communities that are served by single power lines that create single points of failure.[31]

We think **it is vitally important that regulators, utilities, and other participants in the industry continue to put the generic ideas of resilience into practical reality**. That will require more sharing of best practices, especially by regulators and utilities through regional and national institutions. It will require, as well, more research into methods and demonstration of tools that can model reliability and resilience, including greater use of forward-looking models and evaluation of tail risks discussed above. All of these tasks are difficult to perform, especially in the current regulatory and utility system, which has a hard time dealing with uncertainty and deep unknowns and which tends to be organized within particular scopes—whereas resilience is a topic that intrinsically cuts across domains. We are encouraged by the substantial analysis and planning that is starting to be devoted to resilience.[32] It is evidence that, with the right goals and metrics, grid planners and power users have many tools at their disposal to create electric service that aligns with their needs.

Building Transmission

The reliability of electric power supply hinges on both certainty and flexibility. A shift to more intermittent renewables affects the need for and provision of flexibility that can be used by investment planners, market actors, policy makers, and regulators. In response, there are many other sources of flexibility, such as new kinds of supply, systems for storage, and variations in demand. Of these sources of flexibility, transmission plays a particularly important role, because it expands the geographical and market scope for tapping flexibility that could be located anywhere on the grid.[33]

There are two, seemingly opposing, stories being told today about transmission. One story is crisis. A big shift to electric power will require doubling or perhaps tripling the size of the grid—with a particularly critical role for large, long-distance transmission lines.[34] Yet it takes seven to ten years to plan and build new transmission: Time is needed related to legal challenges, siting, permitting. Worse, many projects fail due to local opposition, often anchored in concerns about land use. A major project in Maine that would carry clean hydropower from Canada to US markets failed when a brew of local political concerns—NIMBYism, more or less—combined with opposition from owners of existing power plants that would have become less profitable if new transmission made it easier to import more electricity.[35] These long lead times along with low success rates are incompatible with current-grid carbon reduction goals. They also contribute to growing concerns about grid reliability.

The other story is pretty much the opposite. While power line projects do face opposition, many still get built with good planning and long time horizons. Vertically integrated power companies in particular seem to have found ways to site these projects—and their regulators are highly supportive. Moreover, new technologies—such as high-voltage, direct current (HVDC), now highly mature—make it possible to pack more power into a single line. A crisis in transmission is easy to imagine but not much evident in reality.

This asymmetry may reflect, in part, an imbalance in the political and economic pressures that help determine which lines are built. When a transmission line or upgrade is essential for reliability, it has a very high probability of success. Politically aware regulatory processes abhor blackouts. As the purpose of a line shifts—toward economic savings from congestion relief or opening up remote areas for hypothetical new (generally renewable) generation—the prospects of success plummet, because the political forces arrayed behind the project become less compelling.

Looking across the nation, we see merit in both stories. There are parts of the country—especially in the West and Northeast—where unmet new transmission needs are seen to be rising.[36] In other parts, such as the Southeast and Midwest, the systems for new lines seem to be working better. Even where it is working, however, there will be big challenges in the kind of grid expansions needed to make deep cuts in emissions from the electric power system and rely more heavily on renewable sources. For example, massive volumes of wind are being deployed from Oklahoma up through the middle of the country—a huge resource, but one that remains far from areas of demand. Big new power projects crossing many states—with many intrinsic holdup risks—will be needed. Similar stories will unfold with the rich resources of offshore wind on both coasts and huge solar potentials in the Southwest—all attractive for their physical resources, but far from most load centers.

Technology can help, but it won't fix the transmission problem. While it has proved possible to expand radically the carrying capacity of individual power lines (and still more research will expand that further), these big power lines are also single points of failure—more critical than even the largest of the nation's nuclear plants—and thus require redundancy (e.g., additional lines via distinct routes). Big lines beget big lines.

The problem is parochial and familiar. We think that most of the statutory tools needed to address this problem are already available. For gas pipelines, FERC has clear siting authority and uses it. For electric transmission, FERC's role is less clear, and absent a more muscular approach, FERC leaves essentially all siting issues to the states. Politically, the states don't ask FERC to step in, even when FERC could organize transmission solutions that are in the collective interest. And industry, which usually gains from better transmission (even if some individual firms do not, as in the case of Maine), isn't in a position to lobby FERC to override state authorities.

For nearly all large interstate transmission projects, FERC actually has backstop authority to override some local opposition. But it treats that authority with severe caution—wary of overreaching, understandably in light of parochial interests and litigation risks. And the states are wary of having transmission projects foisted on them. Some people dream of giving FERC much stronger siting authority—similar to what it has for gas pipelines—but that would require new legislation for which there is no reasonable path to success right now.[37]

In this current array of authorities and political gridlocks lies a solution. FERC must assert greater authority. The practical realities remain that asserting such authority is difficult and filled with political risk; **FERC must focus on high-priority areas. DOE can help by identifying transmission projects of greatest value, and recommendations to that end are now being advanced at DOE.**[38]

The idea of setting clearer priorities—and then having FERC (and others) focus their difficult work on those high-priority projects—is not new. In 2005, the Energy Policy Act gave DOE the authority to designate high-value transmission corridors. But DOE was sued, lost its central legal arguments, and shrank from the task. (DOE couldn't even get the data they needed for the work.)[39] FERC has established and is hosting a FERC–state transmission task force that engages in some joint planning and has issued draft rules that envision the states taking the lead in setting priorities (including allocation of costs) and siting.[40] A few regions have also demonstrated how governor-led efforts can produce some coordination, albeit through slow processes of consultation and consensus.[41] Much more collaboration in regional planning is needed, probably with institutions dedicated to the task. Meanwhile, while FERC and DOE have occasionally worked together on transmission planning when directed by legislation, FERC does not routinely ask DOE's help on transmission priorities.[42] In this mixture of divided responsibilities, ambiguous federal authority, and lack of much conviction about the importance of setting transmission priorities, today's problems of stasis have become ingrained. With more attention to transmission priorities will come a need for more clarity on likely locations for large installations of renewable supplies, since those will help determine transmission grid needs.

The time is now—pointing back to existing legal authorities at DOE and at FERC—for a major ongoing joint initiative on transmission priorities in parts of the country that have not been able to do that on their own. The idea is *not* to draw lines across the American countryside and build every line, but to use modern tools for transmission planning to identify major lines that will have the greatest value for reliability. Those lines are where DOE, state regulators, and investors can then apply more of their resources—including resources that can help with siting, such as helping to identify the kinds of win-win solutions needed to get more support from opposing communities and those asked to pay for new lines without commensurate economic savings. This approach allows a focusing of political effort on important projects rather than setting artificial speedy deadlines on the siting process or rolling back environmental protections—strategies that have been attempted before and have always failed. Among many other benefits, this approach to setting priorities will allow more focus on the shifting politics of siting infrastructure—in many regions, for example, there is much more profound awareness of how industrial projects affect "environmental justice" and a growing array of tools that can be responsive to such concerns.[43] A Senate political deal made in tandem with the reconciliation passage of the 2022 IRA energy and climate legislation, but not immediately clarified or codified, appeared to suggest such a priority-based permitting approach for about two dozen energy infrastructure projects, including transmission lines.[44] There are many tools that can help turn projects that seem beset with difficulties into success—with a combination of carrots (e.g., local incentives) and sticks (preemption, including at the federal level, where necessary).

Reforming Innovation

Finally, and most briefly, we look at the generation and testing of new ideas—a process that requires investment in research, development, and demonstration (RD&D) along with the testing of new technologies and business concepts. The value of innovation to most industries is well established. So is the ability of government to identify effective RD&D priorities and fund them.[45]

For several decades, the electricity RD&D system was in crisis as federal budget cuts, along with ongoing chaos and uncertainty in utility market and regulatory models, undercut the incentive to invest. Today, the traditional system for performing RD&D related to the electricity sector is in better shape—it is adequate but not spectacular. That system is good at generating ideas, but the path to turning those ideas—especially ideas that, increasingly, come from outside the traditional power sector—into industrial realities remains fraught.

Innovation hinges not just on RD&D, but on the broader production and testing of new concepts and technologies.

The nation has become better at consistently providing resources for early-stage innovation across a variety of energy sectors, with continued bipartisan support in Congress for public funding across administrations, and much better at administering those resources effectively. Valuable work continues in national labs and universities, despite some debate of management models.[46] DOE has experimented with various mechanisms for improving its ability to target early-stage R&D spending on transformational technologies, such as through ARPA-E. For the most part, those innovations—and similar innovations in loan guarantee programs—have been successful. National public sector R&D budgets are climbing, albeit slowly.[47]

Meanwhile, the core institution for applied innovation in the utility industry, EPRI, is in solid shape and growing; it is one of the major mechanisms for not just performing R&D but also keeping the United States connected to the global frontier. Familiar problems remain, of course, such as the reality that the business model of utilities still has not lent itself to R&D because many state legislators and regulators are wary of allowing too much rate recovery for utility R&D.[48] With so much of the political pressure for transforming the grid coming from the state level—perhaps even more so in the future, with federal policies facing political gridlock—there is a big mismatch between the places where most grid experiments are needed and the locations and modes through which the needed innovation is funded. To that end, the R&D efforts of EPRI and individual utilities tend to be more focused on discrete components, on nearer-term needs, or on prudent if marginal improvements.

This is valuable and should continue. Where much more attention is needed going forward, however, is in funding and managing later-stage innovation, such as with transformational large-scale demonstration projects that can be too risky for most firms to attempt on their own balance sheets. These later-stage investments are more costly, the track record of success is more mixed, and public support for such spending is more ephemeral as well.

The unmet agenda for electric sector innovation is, therefore, a matter of both scope and institutions. **More funding for RD&D is needed from both the industry and the federal government on broadening the scope of grid innovation to include potentially transformational but risky projects**. This scope includes systems projects that industry groups like EPRI have not traditionally taken on, given their remit. There is still a gap between the trajectory of technologies and processes we see applied today in the electric grid and those expected to be available to underpin a future that is both very low carbon and very reliable and secure. There is also an investment gap in this sector between the United States and its peer competitors globally, where public and private RD&D funding is often comingled.[49] While the 2022 IRA energy and climate legislation devoted only a tiny fraction of its total spending to innovation, it did extend tax provisions to promote the deployment of carbon capture systems and the production of zero-emission hydrogen (which could reduce the costs to firms investing in demonstrations of such systems operating at scale). Importantly, though, with new money, we need new institutional constructs to more credibly use these demonstration projects to actually reduce the risk and improve the attractiveness of follow-on private-sector investment. At its core, such an institution should be driven by projects that the industry actually wishes to be involved in through field trials or operational rules—efforts that are otherwise frowned upon by PUCs (and consumers): in short, a mechanism to use federal funding to cost-share the broad-scope innovation that state regulators otherwise cannot justify covering solely with customer funds.[50]

Because the needs for innovation are so great and the systems for innovation are in such flux, the nation would benefit from a fresh, systematic, and authoritative examination of the national system of innovation for electric power. A consortium of think tanks could orchestrate the effort, funded privately to reduce conflicts of interests if one of the agencies or Congress funded the effort, with the aim of addressing these kinds of questions: What are the current levels and trajectories for public and private spending on innovation related to electric power? How well is the industry identifying and incorporating innovations from other sectors of the economy into the design and operation of the grid? What has been the track record of public institutions for funding and managing the innovation process? Such a consortium should also turn an eye to the question of whether the system is improving, best (and worst) practices, and ideas for reforms that are politically and administratively practical. Special attention is needed to attain the right balance of effort between early-stage (low technology readiness level, or TRL) and later-stage (high TRL) funding. While resources are important, it may be that the institutional arrangements—and making them as effective as possible—is even more important. There are nongovernmental organizations that are expert in energy innovation and public policy, such as the Information Technology and Innovation Foundation (ITIF), that would be logical anchors for this kind of assessment. To be successful, the effort will need to involve industry experts as well as communities.

In addition to committing more robust national funding levels and reforming institutions, **the nation should recognize that clean energy advances have benefited enormously from connections with the broader global economy**. Some of the most important innovations that are transforming the energy system—from solar panels and batteries to wind turbines and, in the future, electrolyzers—have two key attributes that require openness. One attribute is that they advance because the global technological frontier advances—solar, for example, "got cheap" because a succession of governments (and firms) pushed the frontier, and the whole world benefited from those advances.[51] The other attribute is that these technologies within the energy sphere gain, increasingly, from innovations "outside" the traditional scope of energy RD&D—for example, advances in electronics, robotics, and materials pursued for other reasons (or with no commercial gain in mind at all) that then spill into energy.

On the one hand, a vibrant energy RD&D system, therefore, suggests an embrace of globalization at a time when that is unfashionable. On the other hand, we see growing concerns across Western society about the risks of becoming reliant on partners who may not share values—long a concern with fossil energy. Successfully navigating this will require good observation and judgment. As a practical matter, for example, that might mean avoiding the push for domestic requirements for technologies that are particularly prone to global advance—for example, electrolyzers. And it could mean that where onshoring occurs—or must occur for political reasons—that it be designed in ways that enhance local benefits while not cutting off access to the global frontier. A balanced approach should seek to sustain continued American interests in energy innovation without compromising our security.

This essay reflects the George P. Shultz Task Force on Energy and Climate electric grid transformation work group chair's summary of a series of structured roundtable discussions on midterm barriers and gaps in the ongoing restructuring of the US electric grid. It conveys the variety of input offered by work group participants but is not intended as a consensus document. David Fedor of the Hoover Institution and Rob Buechler, Stanford University PhD student, were instrumental in support of this essay's development.

NOTES

1 Wm. A. Wulf, "Great Achievements and Grand Challenges," *The Bridge* 30, nos. 3–4 (Fall/Winter 2000): 5, https://www.nae.edu/File.aspx?id=7327&v=e3a8f2e0.

2 Robert J. Gordon, *The Rise and Fall of American Growth: The US Standard of Living since the Civil War* (Princeton, NJ: Princeton University Press, 2016).

3 National Academies of Sciences, Engineering, and Medicine (NASEM), *The Future of Electric Power in the United States* (Washington, DC: The National Academies Press, 2021), https://doi.org/10.17226/25968.

4 For example, see three recent deep decarbonization studies: Eric Larson, Chris Greig, Jesse Jenkins, Erin Mayfield, Andrew Pascale, Chuan Zhang, Joshua Drossman, et al., "Net-Zero America: Potential Pathways, Infrastructure, and Impacts," final report, Princeton University, October 2021, https://netzeroamerica.princeton.edu/the-report; Sustainable Development Solutions Network (SDSN), "America's Zero Carbon Action Plan," 2020, https://www.unsdsn.org/Zero-Carbon-Action-Plan; and San Diego Gas & Electric (SDG&E), "The Path to Net Zero: A Decarbonization Roadmap for California," April 2022, https://www.sdge.com/sites/default/files/documents/netzero2.pdf. The exact relationship between volume and grid size depends on a host of behavioral factors, such as when people charge their electric vehicles, that are essentially unknowable today. It depends as well on whether there is adequate investment in energy efficiency alongside electrification.

5 An initial Rhodium Group analysis estimated that the 2022 legislation's tax provisions would avert 10 to 20 gigawatts of existing nuclear retirement through 2030, while doubling annual capacity additions of renewables to 35 to 77 gigawatts per year through 2030. Even with the nuclear extensions, this would still suggest a faster shift toward intermittent generation. See John Larsen, Ben King, Hannah Kolus, Naveen Dasari, Galen Hiltbrand, and Whitney Herndon, "A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act," Rhodium Group, August 12, 2022, https://rhg.com/research/climate-clean-energy-inflation-reduction-act.

6 US Energy Information Administration (EIA), "Short Term Energy Outlook," May 2022. https://www.eia.gov/outlooks/steo/report/electricity.php.

7 International Energy Agency, "Securing Clean Energy Technology Supply Chains," July 2022, https://www.iea.org/reports/securing-clean-energy-technology-supply-chains.

8 For recent appraisals of physical and cyber risks to the grid, see: NASEM, *Enhancing the Resilience of the Nation's Electricity System* (Washington, DC: The National Academies Press, 2017), https://doi.org/10.17226/24836; and National Research Council, *Terrorism and the Electric Power Delivery System* (Washington, DC: The National Academies Press, 2012), https://doi.org/10.17226/12050. Growing concern about cybersecurity is real but also prone to imagination that exceeds lived reality. So far, the greater threats to the grid remain the familiar ones created by inclement weather along with, in some regions, wildfire.

9 See for example: by industry, SDG&E, "Path to Net Zero"; by academia, Larson et al., "Net-Zero America"; or by environmental and policy groups, Jane Long, Ejeong Baik, Jesse D. Jenkins, Clea Kolster, Kiran Chawla, Arne Olson, Armond Cohen, et al., "Clean Firm Power Is the Key to California's Carbon-Free Energy Future," *Issues in Science and Technology*, March 24, 2021, https://issues.org/california-decarbonizing-power-wind-solar-nuclear-gas.

10 Even this statement is not without controversy. For some observers, the grid itself may be too reliable and society would benefit if the nation invested less in grids of today's reliability and left individual customers to complement grid resources with their own investments in reliability and resiliency where that makes sense. Our deliberations did not adopt that perspective.

11 Doing this research is a high priority—especially research that looks at the interactions of human behavior and technologies such as charging systems that can intelligently aggregate loads based on grid conditions. Similar issues arise for buildings, as described extensively in Andrew Satchwell, Mary Ann Piette, Aditya Khandekar, Jessica Granderson, Natalie Mims Frick, Ryan Hledik, Ahmad Faruqui, et al., "A National Roadmap for Grid-Interactive Efficient Buildings," Lawrence Berkeley National Laboratory, May 2021, https://eta-publications.lbl.gov/publications/national-roadmap-grid-interactive. Together, electric vehicle and building loads are particularly important, because they are expected to account for most of the new load as the economy decarbonizes through electrification.

12 In some of the country, the existing solutions appear to be working well, such as vertically integrated utilities that operate, by design and regulation, to design and engineer grids with high reliability. In other parts of the country, various types of restructuring have attempted—with varying outcomes—to introduce more competition.

13 The Electric Power Research Institute's Resource Adequacy Initiative has recently highlighted these issues in "Resource Adequacy for a Decarbonized Future: A Summary of Existing and Proposed Resource Adequacy Metrics," April 25, 2022, https://www.epri.com/research/products/000000003002023230.

14 Among the many unknowns (and unknowables) today are variability in new power demand from EV charging and from building electrification. EV loads could be huge and highly responsive to grid conditions with the right market structures (and probably a large amount of demand aggregation made possible by new technology).

15 Maximilian Auffhammer, Patrick Baylis, and Catherine H. Hausman, "Climate Change Is Projected to Have Severe Impacts on the Frequency and Intensity of Peak Electricity Demand across the United States," *PNAS* 114, no. 8 (February 2017): 1886–91. https://doi.org/10.1073/pnas.1613193114.

16 Michael T. Craig, Jan Wohland, Laurens P. Stoop, Alexander Kies, Bryn Pickering, Hannah C. Bloomfield, Jethro Browell, et al., "Overcoming the Disconnect between Energy System and Climate Modeling," 6, no. 7 (June 2, 2022): 1405–17, https://doi.org/10.1016/j.joule.2022.05.010.

17 This statement is less pertinent in parts of the country that continue to have vertically integrated utilities that do longer-term investment planning using integrated resource plans (IRPs) around which utilities, regulators, and other policy makers align. (In such settings, however, there may be a need to extend the IRP time horizon as investments are contemplated that have large impacts on grid configuration.). But the challenges may be particularly large for regulatory and planning systems that have fragmented authority, such as in California where

long term planning is shared by two regulators (the California Public Utilities Commission [CPUC] and CAISO) and one agency whose responsibilities include strategy as well as R&D (California Energy Commission). Ambiguities in authority in these systems can impede the creation of more strategic, integrated guidance to investors and market players. A recent example is CAISO's recommendations to procure access to additional out-of-state capacity in advance of the state's fall 2020 blackouts, reportedly not fully accepted by the CPUC. Anne C. Mulkern and Peter Behr, "Blackouts Threaten Heat-Ravaged Grid," *Energy and Environment News*, August 18, 2020, https://www.eenews.net/articles/blackouts-threaten-heat-ravaged-grid.

18 See US DOE Grid Modernization Initiative, https://www.energy.gov/gmi/grid-modernization-initiative and its associated Grid Modernization Laboratory Consortium, https://www.energy.gov/gmi/grid-modernization-lab-consortium.

19 US DOE ARPA-E, "Generating Realistic Information for the Development of Distribution and Transmission Algorithms," January 2016, https://arpa-e.energy.gov/technologies/programs/grid-data.

20 See, for example: the use of the PLEXOS model in SDG&E 2022; the use of the hourly urbs model by a Stanford team in Long et al., "Clean Firm Power Is the Key"; and the use of the RECAP probabilistic production cost model in Energy & Environmental Economics, "Resource Adequacy in the Desert Southwest," February 2022 https://www.ethree.com/projects/resource-adequacy-in-the-desert-southwest.

21 See, for example: the recent three-year planning study undertaken by the municipal utility Los Angeles Department of Water and Power together with the National Renewable Energy Laboratory (NREL): Jaquelin Cochran and Paul Denholm, eds., "Los Angeles 100% Renewable Energy Study," NREL/TP-6A20-79444, March 2021, https://maps.nrel.gov/la100; or the investor-owned utility vision Southern California Edison, "Pathway 2045: Update to the Clean Power and Electrification Pathway," November 2019, https://www.edison.com/home/our-perspective/pathway-2045.html; or New York City, "Pathways to Carbon-Neutral NYC: Modernize, Reimagine, Reach," April 2021, https://www1.nyc.gov/assets/sustainability/downloads/pdf/publications/Carbon-Neutral-NYC.pdf.

22 States with IRP planning horizons beyond ten years include North Carolina, South Carolina, Tennessee, Georgia, Alabama, Mississippi, Louisiana, Arkansas, and Indiana.

23 As demonstrated in Long et al., "Clean Firm Power Is the Key."

24 For example, on social influences in distributed energy resources, see Anna M. Brockway, Jennifer Conde, and Duncan Callaway, "Inequitable Access to Distributed Energy Resources Due to Grid Infrastructure Limits in California," *Nature Energy* 6 (September 2021): 892–903. https://www.nature.com/articles/s41560-021-00887-6.

25 As argued in Charles Sabel and David Victor, *Fixing the Climate: Strategies for an Uncertain World* (Princeton, NJ: Princeton Press, 2022).

26 Regarding the Texas blackouts, NERC CEO James Robb testified, "The natural gas system was not built or operated with electric reliability first in mind. . . . Our gas system, quite frankly, is designed for industrial use and space heating. It's not designed to serve large power plants." Among the many issues identified in contributing to that experience was that critical gas compressor stations were powered off the electric grid. See Erin Douglas, "Paperwork Failures Worsened Texas Blackouts, Sparking Mid-storm Scramble to Restore Critical Fuel Supply," Texas Tribune, March 18, 2021, https://www.texastribune.org/2021/03/18/texas-winter-storm-blackouts-paperwork.

27 Xcel Energy, "Xcel Energy Institutes Controlled Electric Outages for Summit and Grand County Customers; Asks for Conservation in Response to Wildfires," press release, December 30, 2021.

28 Increasing gas–electric interdependence issues are highlighted in NASEM, *Future of Electric Power*, and earlier in Gerad Freeman, Jay Apt, and Michael Dworkin. "The Natural Gas Grid Needs Better Monitoring," *Issues in Science and Technology* 34, no. 4 (Summer 2018). https://issues.org/the-natural-gas-grid-needs-better-monitoring. See as well NERC, "2022 State of Reliability: An Assessment of 2021 Bulk Power System

Performance," July 2022, which encourages utilities to "conduct studies to model plausible and extreme natural gas disruptions" (p. viii,), https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf.

29 Utilities and regional transmission organizations (RTOs) have begun to study aspects of these interactions. PJM's (Pennsylvania, New Jersey, and Maryland) iterative fuel security analysis project in recent years has layered additional complexity on top of conventional weather-driven fuel disruption considerations, for example combined with the evolving resource mix, coal retirements, or cyberattacks; see, for example, PJM, "Fuel Security Update," June 10, 2021, https://www2.pjm.com/-/media/committees-groups/committees/oc/2021/20210610/20210610-item-13-fuel-security-update-presentation.ashx#. And Southern Company and GTI in 2021 initiated a joint R&D effort on hydrogen-blending interactions in the gas pipeline network; see, for example, Emma Penrod, "Southern Company, GTI, DOE Launch Study of Hydrogen-Gas Blend Impacts on Gas Infrastructure," Utility Dive, February 22, 2021, https://www.utilitydive.com/news/southern-company-gti-doe-launch-study-of-hydrogen-gas-blend-impacts-on-ga/595413. Understanding combined interactions among these emerging grid complexities—including, for example, correlations with communications systems on which many aspects of the grid are now reliant—is an unaddressed next step; NERC, "2022 State of Reliability," for example, highlights the emerging concern of solar or battery storage inverters tripping offline during mid-day peak load events (p. vii).

30 Holy Cross Energy, "Primergy Solar Completes 5 MW Solar Array for Holy Cross Energy in Pitkin County," press release, October 26, 2021, https://www.holycross.com/primergy-solar-completes-5-mw-solar-array-for-holy-cross-energy-in-pitkin-county.

31 See Hilal Katmale, Sean Clark, Thomas Bialek, and Laurence Abcede, "Borrego Springs: California's First Renewable Energy–Based Community Microgrid," California Energy Commission, February 5, 2019, https://www.energy.ca.gov/publications/2019/borrego-springs-californias-first-renewable-energy-based-community-microgrid; and Enchanted Rock, "H-E-B considers adding microgrid technology to San Antonio area stores," press release, August 30, 2017, https://enchantedrock.com/heb-considers-adding-microgrid-technology-san-antonio-area-stores. More research is needed to understand costs and benefits and the cost responsibility of nonparticipants.

32 NERC, "2021 Long-Term Reliability Assessment," December 2021, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

33 See Richard Schmalensee and Vladimir Bulovic, "The Future of Solar Energy," Massachusetts Institute of Technology Energy Initiative, 2015, https://energy.mit.edu/research/future-solar-energy. Transmission's role in the "flexibility supply curve" is memorably visualized in Jaquelin Cochran, Mackay Miller, Owen Zinaman, Michael Milligan, Doug Arent, Bryan Palmintier, Mark O'Malley, et al., "Flexibility in 21st Century Power Systems," National Renewable Energy Laboratory, May 2014, https://www.nrel.gov/docs/fy14osti/61721.pdf.

34 Among the most careful looks at the implications of electrification on transmission needs in the United States is Larson et al., "Net-Zero America."

35 Ethan Howland, "Maine DEP Suspends Permit for 1.2 GW Avangrid Power Line to Import Power from Hydro-Québec," *Utility Dive*, November 24, 2021, https://www.utilitydive.com/news/avangrid-nextera-necec-transmission-maine-ballot/608877.

36 Even there, some projects are advancing. See, for example, the Energy Gateway project as described in Peter Behr, "What an $8B Western Grid Project Means for US Clean Energy," *E&E News*, July 14, 2022, https://www.eenews.net/articles/what-an-8b-western-grid-project-means-for-u-s-clean-energy.

37 With existing legislative authority, FERC is taking a few steps in this direction, but the problem of setting priorities remains. For example, see FERC Docket No. RM21-17-000, "Building for the Future Through Electric

Regional Transmission Planning and Cost Allocation and Generator Interconnection," issued April 21, 2022, and subsequent Notices of Proposed Rulemaking.

38 US DOE Secretary of Energy Advisory Board, "Recommendations on Grid Modernization Presented to the Secretary of Energy," June 2022. https://www.energy.gov/sites/default/files/2022-06/SEAB_GridModernization Recommendations_June2022.pdf. This report emphasizes that DOE should not put money into a lot of different small projects, because it won't "transform" the grid from today's configuration. Instead, there is a need to triage which transmission lines can be built next into three tiers based on project development and feasibility. Then bring in FERC where needed and wanted.

39 Jonathan Brightbill, Raymond Wuslich, and Madalyn Brown, "Will the Infrastructure Investment and Jobs Act Accelerate Transmission Development?" Winston & Strawn LLP, January 4, 2022, https://www.winston.com/en/winston-and-the-legal-environment/will-the-infrastructure-investment-and-jobs-act-accelerate-transmission-development.html.

40 As above, regarding Docket No. RM21-17, see FERC, "FERC Issues Transmission NOPR Addressing Planning, Cost Allocation," press release, April 21, 2022, https://www.ferc.gov/news-events/news/ferc-issues-transmission-nopr-addressing-planning-cost-allocation.

41 See, for example, the 2005 "Protocol among the Members of the Midwest Governors Association Regarding the Permitting and Siting of Interstate Electric Transmission Lines in the Midwestern United States," which specified, "Each signatory to this Protocol will support legislation to give state permitting and siting authorities explicit authority: a) to effectively coordinate and cooperate with other governmental permitting and siting authorities on permitting and siting activities regarding proposed electric transmission lines that cross state and national boundaries; and b) to consider both state and regional needs and planning when evaluating whether a proposed electric transmission line should be approved."

42 See, for example, the DOE–FERC memorandum of understanding regarding American Recovery and Reinvestment Act of 2009–funded Western, Eastern, and Texas interconnection planning: US DOE, "Memorandum of Understanding Between the US Department of Energy and the Federal Energy Regulatory Commission," December 2009, https://www.energy.gov/oe/downloads/memorandum-understanding-between-us-department-energy-and-federal-energy-regulatory.

43 Addressing these kinds of concerns is both a moral and political imperative and part of the growing array of challenges in turning ideas for industrial investment into politically sustainable realities. Among many examples of utilities now grappling with such concerns, see the experience of PJM in coal communities (as they contemplate shutting coal plants and shifting resources elsewhere): PJM Planning Division, "Grid of the Future: PJM's Regional Planning Perspective," May 10, 2022, https://pjm.com/-/media/library/reports-notices/special-reports/2022/20220510-grid-of-the-future-pjms-regional-planning-perspective.ashx; and Dominion's experience reorganizing the company to integrate such concerns into investment planning: Carlos Brown, "Environmental Justice," Dominion Energy, April 20, 2021, https://www.dominionenergy.com/our-stories/environmental-justice. The level of political attention now being given to this issue is demonstrated by $20 billion in funding appropriated under the 2022 IRA legislation that is earmarked for projects responsive to such social concerns.

44 Josh Siegel, "After Democrats Pass Climate Bill, Progressives Vow to Fight Manchin's Permitting Deal," *Politico Pro*, August 12, 2022, https://huffman.house.gov/media-center/in-the-news/after-democrats-pass-climate-bill-progressives-vow-to-fight-manchins-permitting-deal.

45 For example, in the development of the US computer industry as described in National Research Council, *Funding a Revolution: Government Support for Computing Research* (Washington, DC: The National Academies Press, 1999), https://doi.org/10.17226/6323; or in clean energy as described in NASEM, *Accelerating Decarbonization of the US Energy System* (Washington, DC: The National Academies Press, 2021), https://doi.org/10.17226/25932.

46 See T. J. Glauthier, Jared L. Cohon, Norman R. Augustine, Wanda M. Austin, Charles Elachi, Paul A. Fleury, Susan J. Hockfield, Richard A. Meserve, and Cherry A. Murray, "Final Report of the Commission to Review the Effectiveness of the National Energy Laboratories," US Department of Energy, 2015, https://www.energy.gov/labcommission/downloads/final-report-commission-review-effectiveness-national-energy-laboratories.

47 See International Energy Agency, "Energy Technology RD&D Budgets: Overview," May 2022, https://www.iea.org/reports/energy-technology-rdd-budgets-overview; and Hoyu Chong and David M. Hart, "Further Energizing Innovation in Fiscal Year 2023," Information Technology & Innovation Foundation, May 2022, https://itif.org/publications/2022/05/13/further-energizing-innovation-fiscal-year-2023.

48 Some utilities and state regulatory commissions have recognized the value of innovation spending and are supportive of R&D programs, both via local utility programs and collective R&D (e.g., EPRI). For overviews of these possible roles of state public utilities commissions, see comments by Ken Costello, "Research and Development by Public Utilities: Should More Be Done?," and Ron Edelstein, "Utility R&D as a Public Good," presentation to the NARUC subcommittee on gas, November 8, 2015, https://pubs.naruc.org/pub.cfm?id=4AA29DB3-2354-D714-51DB-4CFE5EFE50A7 and https://pubs.naruc.org/pub.cfm?id=4AA63723-2354-D714-51DE-BA07435ACAFE.

49 Larson et al., "Net-Zero America" surveys a collection of overall energy RD&D public funding studies from the past decade that recommended increasing US federal funding levels from an approximate $4 billion annual level (2015 $) to a $10 billion to $17 billion level. Two recent studies further suggest that increases in US public RD&D funding be ramped up more slowly in early-stage R&D and faster in later-stage demonstration, subject to institutional frameworks: Varun Sivaram, Colin Cunliff, David Hart, Julio Friedmann, and David Sandalow, "Energizing America: A Roadmap to Launch a National Energy Innovation Mission," Columbia Center on Global Energy Policy, 2020, https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/EnergizingAmerica_FINAL_DIGITAL.pdf; and American Energy Innovation Council, "Energy Innovation: Supporting the Full Innovation Lifecycle," Bipartisan Policy Center, February 2020, https://bipartisanpolicy.org/report/energy-innovation-supporting-the-full-innovation-lifecycle.

50 A past example was the fifty-fifty cost share between DOE and utilities (after receiving public utility commission funding approval) for smart meters under the American Recovery and Reinvestment Act that led to millions of advanced meters being installed in the United States.

51 Gregory F. Nemet, *How Solar Energy Became Cheap: A Model for Low-Carbon Innovation* (London: Routledge, 2019).

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About the Authors

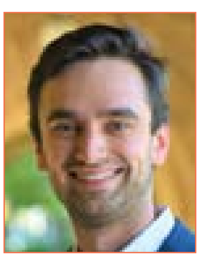
Photo by Erik Jepsen / UCSD University Communications

DAVID VICTOR

David Victor is a professor of innovation and public policy at the School of Global Policy and Strategy at UC San Diego, where he also directs the Deep Decarbonization Initiative. He previously taught energy and environmental law at Stanford Law School. A longtime contributor to the Shultz Task Force, he is also a nonresident senior fellow at the Brookings Institution.

DAVID FEDOR

David Fedor manages the George P. Shultz Task Force on Energy and Climate at the Hoover Institution.



ROB BUECHLER

Rob Buechler is a doctoral student in mechanical engineering at the Majumdar Lab at Stanford University.

George P. Shultz Task Force on Energy and Climate

The George P. Shultz Task Force on Energy and Climate takes a balanced approach toward sustaining the economic, environmental, and security dimensions of energy policy. The Task Force's goal in carrying forward Secretary Shultz's legacy, as established more than fifteen years ago, is to continue his nonpartisan, temperate, and problem-solving approach toward energy and climate questions of US national importance: with balance, so that policies can be sustained over political cycles to match the large scale and long time frames at which the energy world operates; with clarity—both analytical and moral—in appraisals of complex systems; and with a constructive voice, favoring pragmatic steps in the right direction today so as to not get lost in the distance of time or rhetoric. Cochaired by Arun Majumdar and Amb. Thomas F. Stephenson, the task force convenes as needed to respond to emergent energy problems. And it organizes regular, ad hoc expert and practitioner work groups to identify sector-specific midterm risks in the energy transformation and propose novel policies to address them.

This essay reflects the chair's summary of a series of roundtables and other consultations with the George P. Shultz Task Force on Energy and Climate's ad hoc electric grid transformation work group through the spring and summer of 2022. This work group consists of the following:

David Victor, UC San Diego (chair)
Steve Berberich, president and CEO (ret.), California Independent System Operator
Anjan Bose, Washington State University
Stanley W. Connally Jr., Southern Company
Emily Fisher, Edison Electric Institute
Dian Grueneich, Stanford University
Bryan Hannegan, Holy Cross Energy
Arun Majumdar, Stanford University and Hoover Institution
The Hon. William K. Reilly, former administrator, US Environmental Protection Agency
Susan F. Tierney, Analysis Group