WILSON SONSINI

The Basics of Electric Power Regulation for Project Developers

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A Developer U Collaboration

CREO

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About Developer U

Developer U is a recurring two-day workshop, run by CREO in partnership with Wilson Sonsini and Spring Lane Capital, designed for senior executives of climate hardware companies navigating the shift from innovation to commercial deployment. The seminar focuses on core concepts in project development and project finance, essential tools for bridging the "missing middle" financing gap that often hinders climate infrastructure projects. Taught by active industry practitioners, Developer U equips entrepreneurs with both strategic insight and practical skills to implement and scale their projects effectively.

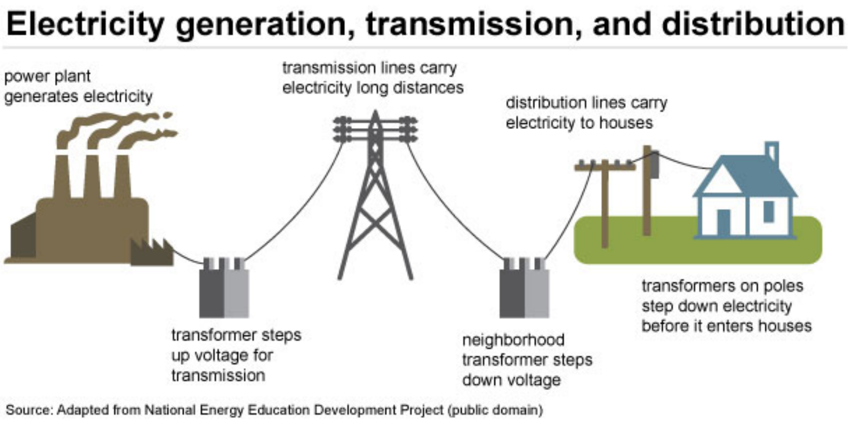
This whitepaper is part of a series developed by Wilson Sonsini, in collaboration with CREO and Spring Lane Capital, to complement the Developer U workshop series. It introduces key concepts critical to the successful development and financing of climate hardware projects, with the goal of equipping stakeholders with the knowledge needed to navigate the complex financing and development challenges in climate technology.

I. Introduction

The purpose of this whitepaper is to provide an overview of U.S. electricity regulation, including the different market structures in the industry, how those markets are regulated, and the primary agencies responsible for regulating the industry. This primer is written principally for readers who are not yet familiar with the details of electricity regulation who seek to attain a working knowledge of the major concepts.

Why should a project developer care about electricity regulation in the first place? Whether the project is an electricity consumer or seller, state and federal electricity regulation is likely to have a profound impact on the viability, economics, and timeline of the transactions and project. Given that electricity is among the most highly regulated industries in the economy, it is critical for developers of energy infrastructure projects to understand and maintain compliance with applicable regulations, as failure to do so can result in failure of a business model, significant penalties, and operational disruptions. Developers of projects that will become large electricity consumers can also find significant opportunities by understanding the basics of electricity regulation. For instance, some large electricity consumers can achieve significant cost savings by participating in demand response programs or choosing an alternative electricity supplier. The existence and value of these opportunities—and their concomitant risks—will depend upon the regulatory regime in the region the project is located.

To understand how electricity is regulated, it's important to first understand the basics of how electricity is traditionally created, transported, and served to customers.[1]



[1] Image is also available at https://www.eia.gov/energyexplained/electricity/delivery-to-consumers.php.

Power plants **generate** electricity from various fuel sources like solar, wind, or natural gas.

Transmission lines carry electricity long distances from generators to population centers like cities or towns. Transmission lines operate at a high voltage to minimize how much electricity is lost over long distances.

Distribution lines carry electricity to end-use consumers over shorter distances. Distribution lines operate at lower voltages so that they can deliver the electricity in a usable form.

II. The Evolution of the Electricity Industry

The regulation of electricity in the U.S. is heavily informed by how the market structures in the industry have evolved over time.

a. Rise of the Vertically Integrated Monopoly

At the inception of the electric industry, electric service was seen as a natural monopoly. Within a given service area, one company owned and operated every part of the electricity system, from generation, to transmission, to distribution. Consumers had no option but to buy bundled power service from the local utility. Monopoly utilities were subject to state regulatory oversight of the retail rates they could charge. This concept is often referred to as a "regulatory compact." In exchange for the exclusive right to operate in a specific area and the guaranteed ability to recover their costs plus a fair return, utilities must submit to government regulation to ensure that electric service is safe, reliable, and affordable.

By 1929, however, the electric utility industry had seen significant growth and consolidation. Most electric utilities were owned by large, complex interstate utility holding companies. These vast holding companies operated in multiple states, which undermined effective state regulation through financial and cost obfuscation and regulatory capture.

b. Early Utility Regulation

In 1935, the U.S. Congress responded to the problems it saw in the electric utility industry. The Federal Power Act vested authority over wholesale sales of power and interstate transmission in the Federal Power Commission (now the Federal Energy Regulatory Commission (FERC or the Commission)). Congress also passed the Public Utility Holding Company Act, which, among other things, restricted utility holding company operations to a single state to help ensure the efficacy of state retail regulation.[2]

These laws solidified the respective split of federal and state jurisdiction over utility regulation, which depends on two key distinctions. First, jurisdiction over the sale of electricity depends on whether the sale is at wholesale (i.e., a sale for resale) or retail (i.e., a sale to an end-use customer). Second, jurisdiction over the transportation of electricity varies based on transmission and local distribution functions. FERC has jurisdiction over wholesale sales and interstate transmission, while states have jurisdiction over retail sales and local distribution networks. This basic federal-state jurisdictional framework persists to this day, but it has been strained and stretched as business models and technologies evolve.

Both federal and state regulatory bodies use the same basic legal standard. Rates, terms, and conditions for service must be "just and reasonable" and may not be "unduly discriminatory" among customers.

c. Creation of the Modern Grid

Between the 1930s and the 1970s, electrification extended across nearly all communities in the U.S. and commercial and industrial manufacturing infrastructure experienced massive growth. As a result, demand for electricity (electric load) increased substantially (greater than five percent per annum), which led to massive investment in utility infrastructure. Utilities built out generation, distribution, and high-voltage transmission networks to connect to neighboring utilities, which improved reliability and reduced costs. Instead of each utility building sufficient reserve capacity on their own, which would be costly and inefficient, utilities entered into contracts to pool their reserves with their neighbors.

d. The Introduction of Competitive Markets

The 1970s brought an energy crisis driven by high costs of oil and gas (driven by OPEC), inflation, and nuclear generation cost overruns. As a result, public sentiment began to shift away from the closed-books of vertically integrated monopolies in favor of market-based competition. In 1978, the Public Utility Regulatory Policies Act (PURPA) took one of the first major steps in opening the market to non-utility power producers. In particular, PURPA required electric utilities to interconnect, transmit, and

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[2] The 1935 PUHCA was largely repealed and replaced by the Energy Policy Act of 2005.

buy power from certain “qualified facilities” (QFs) at the utility’s avoided cost, i.e. the amount it would cost the utility to generate that power itself.[3]

In 1978, and again in 1992, Congress amended the Federal Power Act to encourage competition in electric markets through exemptions from regulation for independent power and a process to gain grid access. The 1990s also ushered in an era of state retail market restructuring. Many states began to “deregulate” their electricity markets and introduce competition and consumer choice at the retail level.

In 1996, FERC issued Order No. 888, which fundamentally transformed the electric industry to address discriminatory behavior by the utilities that owned transmission systems. Specifically, FERC required electric utilities that owned transmission lines to provide nondiscriminatory open access to those lines for all generators. That was a revolutionary change because it required utilities to allow independent generators to access the grid on the same terms that the utilities use the grid themselves. That order laid the groundwork for the creation of modern independent power producers and the development of competitive wholesale electric markets.

In the years following Order No. 888, FERC encouraged the voluntary formation of competitive wholesale electricity markets run by independent system operators (ISOs) and regional transmission organizations (RTOs).[4] RTOs are independent, nonprofit entities that operate the transmission network across large areas. The utilities that own transmission lines in these regions have given over operational control of their transmission system to the RTO, but still retain ownership of the transmission lines.

RTOs also run wholesale energy markets in which generators offer to sell their electricity and load-serving utilities buy electricity to serve their customers. These energy markets are auctions that are centrally cleared at the point where supply matches demand. All generators that “clear” the market receive the market price and proceed to generate the electricity they offered. These energy markets typically include both day-ahead and real-time market components. These markets allow RTOs to dispatch resources more efficiently than a single utility could; instead of one utility dispatching the most efficient resource in its service area, the RTO can dispatch the most efficient set of resources over a footprint covering dozens of service areas.

3 The Energy Policy Act of 2005 later weakened PURPA by creating an exemption from the mandatory purchase obligation.

4 Some of these organizations are also referred to as Independent System Operators (ISOs). The distinctions between RTOs and ISOs have eroded over time. Today, the terms are often used interchangeably. For ease of reference, this paper uses “RTO” to include both RTOs and ISOs.

Some RTOs also have other types of markets in addition to their energy markets. Many RTOs run ancillary service markets. Ancillary services are functions that help RTOs maintain reliability, like voltage or frequency control. Some RTOs also run capacity markets, which pay generators in exchange for the commitment that the generator will be available to produce power when needed. Capacity markets are a mechanism to ensure that power producers build and maintain enough generation to ensure that utilities will be able to meet demand in the future.

e. International Relationships

The U.S. grid is deeply interconnected with the Canadian grid, with over 30 major transmission interties. The U.S. imports significant amounts of Canadian hydropower through these interconnections. While the U.S. and Canadian markets are highly intertwined, the applicable regulatory structures have significant differences. The initial electrification of Canada followed some of the same themes as in the U.S., with initial electrification driven by privately owned, vertically integrated monopolies. However, the markets evolved differently; in the mid-1900s, most provinces created publicly owned utilities. Those publicly owned and vertically integrated utilities continue to exist today in most provinces; only Ontario and Alberta have created ISOs with competitive electricity markets. Provincial governments hold most regulatory authority, including rate regulation and oversight of ISO market rules (in Ontario and Alberta). At the federal level, the Canada Energy Regulator permits intraprovince pipelines and power lines.

III. Today's U.S. Regulatory Landscape

Today, two-thirds of the total annual electricity load of the U.S. is served by one of the seven ISOs/RTOs. The remaining one-third is served by vertically integrated utilities under traditional regulation.

How government agencies regulate electricity—at both the federal and state level—is different depending on the market structure in that region. The following section will provide a general overview of the respective state and federal roles, but it is worth noting that FERC and states have sometimes clashed over those jurisdictional boundaries. As market structures evolve and technology improves, many issues now implicate both federal and state regulators.

a. Federal Regulation

At the federal level, FERC has jurisdiction over wholesale sales and interstate transmission. FERC also approves reliability standards that govern a wide variety of technical topics for the operation of the bulk power system, including frequency and voltage levels, cybersecurity, and emergency preparedness.

FERC's role over transmission is largely consistent across RTO and non-RTO regions. As mandated by Order No. 888 and as amended by subsequent orders, FERC requires utilities and RTOs to have "open access transmission tariffs" on file with the Commission. Those tariffs set out the rates, terms, and conditions for transmission service. Utilities are required abide by the tariffs on file with the Commission. If a utility would like to make changes to that tariff, they can file a proposal with the Commission, which the Commission can approve or reject based on whether it is "just and reasonable" and not "unduly discriminatory or preferential." If another market participant believes that the utility is not properly administering its tariff or that the tariff itself is unjust and unreasonable or unduly discriminatory or preferential, they can file a complaint with the Commission.

To contrast, FERC's jurisdiction over wholesale sales is exercised differently in RTO versus non-RTO regions. In RTO regions, FERC regulates the detailed rules by which the RTO operates each of its wholesale electric markets. Those rules are hundreds or thousands of pages long and are laid out in tariffs that each RTO must file with FERC. All changes to those market rules must be approved by FERC. In non-RTO regions, FERC's role is generally more limited. FERC monitors the bilateral agreements between utilities and power producers to ensure that utilities do not exercise market power.

b. State Regulation

At the state level, public utility commissions have jurisdiction over investor-owned distribution systems and the retail rates that distribution utilities charge customers for electricity. It is worth noting that distribution systems owned by municipal utilities, electric cooperatives, or federal entities are typically not subject to public utility commission regulation. Those entities each have their own regulatory frameworks: cooperatives are often self-regulated by the members, and municipal utilities are typically regulated by a city council or board. For federal entities like the Tennessee Valley Authority or Bonneville Power Administration, the applicable regulatory structure varies based on their enabling statutes. The following section, however, will focus on the regulation of investor-owned distribution systems by public utility commissions.

The names of public utility commissions vary from state to state; they may be called "public service commissions," "corporation commissions," or "regulatory commissions." They also vary in terms of the number of commissioners, how those commissioners are selected (appointed versus elected), what industries other than electricity they regulate, and the organizational structure. However, there are many similar themes and commonalities across various states' public utility commissions in terms of how they approach regulating the electricity system in their state.

In regions with vertically integrated utilities, the state public utility commission is empowered to set the rates that vertically integrated utilities can charge for their electricity and distribution service. Those rates are traditionally set based on the cost of the utility providing service, plus a "fair" rate of return. Through its "rate cases," public utility commissions hear detailed evidence regarding all of the costs the utility incurs to provide service and determines how those costs should be allocated to different classes of customers (for example, the rate structure for residential customers can be different than the rate structure for commercial or industrial customers).

In these traditionally regulated retail markets, state public utility commissions also typically oversee integrated resource planning, which is the process by which utilities plan what generating facilities they will build to meet future demand. Utilities must justify those investment decisions as "prudent" to state public utility regulators. If the state public utility regulators agree that the investments are prudent, then the utility gets to recover the costs of those investments through retail rates. Under that structure, consumers ultimately bear the risk of the utility's investments regardless of how the generating facilities perform.

In states with restructured retail markets, customers have the ability to choose their electricity supplier. As a result, in these markets, the state public utility commissions typically do not set retail electricity prices because the market itself creates competition to ensure retail prices are reasonable. However, the incumbent utility retains monopoly ownership of the distribution system, so the rates for distribution service are still subject to state public utility commission oversight. Many states with restructured retail markets no longer conduct integrated resource planning; instead, some of these states conduct long-term procurement planning or rely on an RTO's capacity market to ensure resource adequacy.

It is also important to keep in mind that other state actors also play important roles in regulating the electricity industry. For instance, states have jurisdiction over the siting of generating facilities. The specific body that approves the siting of generating facilities varies from state to state. Oftentimes, siting is controlled by local governments, but sometimes state public utility commissions or other state-level agencies play a role either in lieu of or alongside a local governmental entity.

IV.Implications for Large Consumers and Developers

All entities that are involved in the electric industry are impacted by the regulatory landscape. The below section will provide an overview of some of the major issues that impact generators and large consumers, as well as issues that impact all parties.

a. Generators

Developing a generation facility is a substantial undertaking with many regulatory hurdles. Many of the specifics will vary based on the size, configuration, and location of the project.

i. Interconnection

One of the key barriers to enter the electricity market is interconnection—the process of physically connecting a generator to the grid. To start the process, a developer must submit an interconnection request to the relevant utility (or RTO). The utility (or RTO) conducts a series of engineering studies to determine what facilities or upgrades are needed to interconnect the generator to the system and maintain system reliability, and how much those facilities or upgrades will cost. The utility (or RTO) then tenders an interconnection agreement to set out the cost and terms of the interconnection.

For utility-scale projects seeking to interconnect to the transmission system, the interconnection process has become a major bottleneck; it often takes several years from the time a project submits an interconnection request to sign an interconnection agreement. For smaller projects seeking to interconnect at the distribution level, the process is typically significantly faster.

There have been some efforts to speed up the interconnection process for utility-scale projects. FERC recently conducted a rulemaking process culminating in Order No. 2023, which, among other things, created new consequences if utilities fail to meet interconnection study deadlines. However, those efforts also have created new challenges for developers. For instance, Order No. 2023 also created more stringent requirements for developers to enter the interconnection queue, including site control requirements, additional financial deposits, and withdrawal penalties for developers that decide not to move forward in the interconnection process. As a result, it is more important than ever for developers to strategically enter the queue at the optimal time to achieve commercial operation by the desired date, while also ensuring that the project is sufficiently well developed such that it meets the readiness requirements and is likely to reach commercial operation.

There is also a growing trend among RTOs in proposing interconnection reforms that allow certain projects to jump ahead of other projects in the queue. These proposals are generally framed in terms of supporting resource adequacy by expediting the review of shovel-ready projects. In practice, however, these proposals tend to favor natural gas projects and projects developed by incumbent utilities. It will be particularly important for independent power producers in the renewables space to engage in the regulatory process to ensure that interconnection processes provide fair and open access to the grid.

ii. Selling Power

Once a generator is interconnected, it still faces several hurdles before it can sell power, either at wholesale or retail. Interconnection agreements grant the right to connect a generator to the grid, but they typically do not grant transmission or distribution service, so the developer will need to make a separate request for transmission or distribution service. The grid is extremely congested in many parts of the country, which leads to the risk that generators may be curtailed if they do not request guaranteed deliverability.

At the retail level, generators can only sell power if the relevant state public utility commission permits it. In states with restructured retail markets, generators can apply for a license from the state public utility commission to become a retail electric provider. In traditionally regulated retail markets, retail sales by entities other than the incumbent monopoly utility are typically prohibited. Generators may be able to sell power in traditionally regulated markets (or avoid full regulation as a retail electric provider in a restructured state), by participating in certain state programs, such as community solar or behind-the-meter generation programs. The details of such program vary state by state.

At the wholesale level, independent power producers typically require long-term offtake contracts (i.e., Power Purchase Agreements) to provide a revenue stream that supports financing for the project. These generators also typically seek to obtain authorization to sell power without triggering full regulation as a utility, which is often done by obtaining QF status or Exempt Wholesale Generator (EWG) status. A facility can qualify as a QF if it is a small renewable generator under 80 MW or a cogeneration facility (i.e., a facility that produce electricity and another form of useful thermal energy like heat or steam). EWG status is available where a company is engaged exclusively in the business of selling energy at wholesale. With some limited exceptions, generators must file a certification at FERC to obtain either status.

Furthermore, unless an exception applies, developers must obtain market-based rate authorization from FERC to sell wholesale electricity at market-based rates rather than cost of service rates, regardless of whether those transactions will occur through an RTO market or through bilateral contracts. FERC grants the authority to sell power at market-based rates if the seller can demonstrate that they lack market power or have adequately mitigated their market power. Once a seller obtains market-based rate authorization, there are ongoing regulatory requirements to keep in mind. Sellers must file an electronic quarterly report of all their transactions each quarter, file a “notice of change” if there is a change in the facts that the Commission relied on to grant market-based rate authority, and certain sellers need to file updated market power analyses every three years. Importantly, FERC market-based rate authorization only permits independent power producers to sell power at wholesale. Independent power producers can only sell power directly to end users (like data centers) where permitted by state law. As noted above, in regions with vertically integrated utilities, state law typically prevents entities other than the incumbent utility from selling retail power to end users.

iii. Prior Approval for Transactions

Public utilities or holding companies that seek to engage in certain transactions whose value exceeds $10 million must obtain prior authorization from FERC. Specifically, companies must obtain FERC approval for sales, leases, or disposals of FERC-jurisdictional assets (which includes “paper facilities” like tariffs or contracts for energy or transmission service), mergers, acquisition of securities, or acquisition of existing generating facilities that are used for interstate wholesale sales. Holding companies that directly or indirectly own or hold more than 10 percent of voting securities in a public utility company must obtain FERC approval to acquire over $10 million worth of securities or merge with other public utilities or other public utility holding companies.

b. Consumers

It is important for commercial and industrial entities that use large amounts of electricity to be aware of the energy regulatory framework in their region(s). Options for energy procurement vary based on location and market structure. In traditionally regulated markets with vertically integrated utilities, customers generally have no choice but to purchase electricity from their local electric utility. In deregulated markets, however, customers have the option of selecting an electric supplier. In those markets, large customers can and should shop around to ensure they get the best deal through, for example, issuing a request for proposal to energy suppliers. It is also common to hire an energy advisor or broker that help customers navigate complex markets, provide informed forecasts of future prices, undertake commodity trading and financial or physical hedging, and suggest other measures to balance price level, certainty, volume availability, and other commercial considerations.

Consumers can also reduce energy costs or earn incentive payments by participating in demand response programs. Demand response programs encourage customers to use less electricity during peak demand periods. Consumers can either participate in utility-run programs or sign up with a thirdparty demand response aggregator, who combines the loads of multiple customers and offers that collective energy reduction into wholesale electricity markets. For consumers whose electricity demand can be curtailed or shifted to off-peak hours, demand response programs can be a great option.

c. Cross-Cutting Issues

All major players in the electricity industry are impacted by the shifting regulatory landscape. Energy laws, regulations, and markets were originally designed for dispatchable generation with significant marginal costs. Those regulatory and market rules must adapt to changes in technology and newer resource types. For example, regulated markets needed significant adjustments to accommodate wind and solar resources, which are intermittent resources with low or zero marginal cost. Similarly, energy storage resources are an entirely different asset class from traditional generators; significant regulatory changes were needed to facilitate energy storage resources' full participation in the markets.

To encourage the adoption of clean energy and reduce greenhouse gas emissions, many states have adopted Renewable Portfolio Standards (RPS) that require utilities to source a specific percentage of their electricity from renewable energy sources. While the details of RPS requirements vary by state, utilities typically can meet RPS obligations by either generating renewable energy themselves or purchasing renewable energy certificates (RECs). RECs are an important tool to track the generation and consumption of renewable energy because when renewable power is added to the grid, it is indistinguishable from power generated from fossil fuels. RECs can be sold either "bundled" with physical electricity or "unbundled" (i.e., separate from physical electricity). RECs are not regulated by FERC; however, state public utility commissions often have rules about how RECs are created, transferred, and retired. RECs create another potential revenue stream (albeit, typically a modest one) for independent power producers that build renewable energy, while large consumers that seek to buy clean energy often do so by purchasing RECs.

One of the pressing challenges hindering the integration of new resources and technologies is the current lack of available capacity on the grid. Very little transmission or distribution capacity has been built in the last few decades. As a result, the grid is congested, which makes it more difficult for new generators to interconnect and for new loads to be served. Interregional transfer capability is still limited, which restricts the amount of energy that can be traded across regions. Although FERC recently implemented reforms to the transmission planning process in Order No. 1920, building new transmission lines has become politically polarized, and it is yet to be seen whether FERC's efforts will bear fruit.

As a result of limited transmission and distribution capacity, there is a growing trend to co-locate new loads like data centers with generating facilities. Direct access to generation can potentially lower electricity costs for large loads and can provide significant new opportunities for generation developers. However, there is significant uncertainty in the regulatory landscape. There are open proceedings at FERC on this topic, but the rules that will apply to co-location arrangements are still unknown.

Constraints in transmission, distribution, and generation capacity has also spawned the development of innovations like virtual power plants (VPPs), where distributed energy generation, storage, and demand response resources are virtually aggregated and intelligently deployed to satisfy loads. VPPs optimize the use of these distributed energy resources and thus can enable rapid load growth with lower capital cost. These business models are subject to both state and federal electricity regulation. Distributed energy generation resources—which can be owned by residential, commercial, or industrial customers—typically must interconnect to the local distribution system through a state-regulated process implemented by the local utility. The entities that aggregate distributed energy generation resources into VPPs can choose whether to participate in wholesale or retail markets. FERC Order No. 2222 required RTOs to allow DER aggregators to participate in their wholesale energy markets, but the implementation of that requirement has been slow and inconsistent. As a result, the outlook for VPP wholesale market participation varies substantially by region. State programs to enable VPP participation in retail markets also vary widely from state to state and sometimes even between different utilities' service areas within the same state. Given the patchwork of rules governing VPPs, it is important for both VPP aggregators and VPP participants to understand the regulatory landscape in their region and stay abreast of new developments.

Grid constraints are also leading to the proliferation of microgrids—localized energy systems that integrate distributed energy resources to serve local loads. Microgrids can operate independently from the main utility grid, which can help keep critical loads online during outages. Microgrids are also beneficial for electric vehicle charging infrastructure, as they can help smooth peak demand and potentially minimize the need for expensive grid upgrades. However, the regulatory landscape for microgrids is complex; they do not fit neatly into traditional market models. Certain states, like California and New York, have created programs to incentivize and integrate microgrids, but most states lack dedicated regulatory frameworks for microgrids, leading to significant regulatory uncertainty.

In the backdrop of all these regulatory changes to respond to new technologies and market structures—many of which arise from efforts to combat climate change—the electric industry also faces major impacts from the effects of climate change that are already here. Extreme weather events are becoming more and more common, and these events pose significant challenges for grid operators. Wildfires pose severe threats to utility infrastructure, especially distribution lines, leading to costly repairs and extended outages. It is impossible to overstate the significant threat climate change poses to grid stability, reliability, and affordability.

V. Conclusion

While the landscape of electricity regulation is multi-layered and complex, its evolution over time is characterized by iterative progress towards more open, fair, and competitive markets. It is critical to ensure that this trend continues to enable the ongoing shift to a cleaner, smarter, and more resilient grid. Although powerful incumbents continue to control key regulatory barriers, today's challenges also provide an opportunity to advocate for the regulatory innovation that is necessary to allow independent companies to compete with new services, technologies, and business models.

For more information on how to navigate the regulatory structures that impact project developers, please contact Wilson Sonsini's Energy and Climate Solutions practice.

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