DISSERTATION

REGULATORY DRIFT AND PATH DEPENDENCE IN DISTRIBUTED GENERATION POLICIES ACROSS US STATES

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ABSTRACT

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At this moment in the technological transition toward clean energy resources, two related strands of social science research deserve further empirical study: (1) the drivers of policy change, or alternatively, the factors that inhibit comprehensive policy change, and (2) the politics surrounding the regulation of clean energy technologies. Regarding the latter, this study is particularly interested in regulatory frameworks governing small-scale systems located close to the point of electricity consumption, or *distributed generation* systems, or DGs. Much of the political science and energy policy literature examines the drivers of policy change for renewable technologies writ large, but fewer studies have taken a focused approach on the policy mechanisms to drive adoption of renewable technologies specifically within small- and mid-size markets for residential and commercial properties. Because the regulatory environment for DGs is largely shaped by state policymakers, this research seeks to understand the sources of institutional resistance toward policies that would expand DG deployment at the state level.

Two concepts in the political science and public policy literature potentially explain resistance toward updating regulatory frameworks to facilitate the technological transition. The first is *path dependence*, which explains how institutions become locked-in to outdated technologies due to increasing returns. The second is *policy or regulatory drift*, which illustrates how institutions avoid comprehensive change and remain stuck using regulatory structures that become inadequate for addressing social and environmental risk as circumstances evolve. This dissertation is focused on the following research question: what can explain the variance in path dependence and regulatory drift across states' regulatory regimes, specifically in DG integration policy? To answer this question, I conduct quantitative analyses of the association of political and economic variables with pro-DG policy outcomes across a seven-year period, from 2012 to 2018. Chapter Three analyzes the state policy environment using a quantitative index measure factoring in a series of DG integration policies, emphasizing net energy metering and interconnection standards. Chapter Four analyzes a similar set of political-economic and technical variables against the likelihood of pro-DG decisions from public utility commissions.

The study finds some support for the hypothesis that path dependence and regulatory drift is occurring across states' DG policy environments, but the independent variables of interest – coal generation, utility market concentration, and power system characteristics – exert an uneven impact on DG policy outcome. Statistical relationships are conditional upon geographic region and electricity price and interpreting results across the two quantitative models is not clear-cut. This project contributes to our understanding of drift and path dependence in DG policy by providing a snapshot of the observable relationships between political-economic factors and regulatory favorability toward DG, and further research can utilize this project as a springboard to precisely identify the drivers of DG policy outcomes or discuss the role of drift in phases of technological change.

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Introduction

The social and environmental risks introduced by climate change are manifold, presenting an arduous challenge for policymakers. Extreme weather events such as hurricanes, heat waves, and polar vortexes driven by shifting average temperatures presents threats to public safety and critical infrastructure. Droughts are expected to worsen and exacerbate the megadrought affecting the western United States, significantly reducing groundwater supplies and increasing the frequency, severity, and geographic range of forest wildfires. Droughts exert unprecedented pressure on agriculture and international trade as freshwater scarcity drives diminishing crop yields. Sea-level rise exposes the vulnerability of coastal communities and the need to adapt to changing environmental conditions, and increased precipitation poses similar risks in the form of tidal and inland flooding (IPCC 2014). All of the risks listed and beyond present grave ramifications not only for community health and resilience, but also to economic stability and energy security. The above threats, especially extreme weather events, directly impinge upon the reliability of the energy system as electricity infrastructure faces profound vulnerabilities. Events such as the Texas grid crisis of February 2021 highlight the risks to infrastructure from climate-related disruptions. Protecting the public, natural resources, and infrastructure from climate risks is the critical challenge of the 21st century.

To respond to these risks, world leaders coalesced around the Paris Agreement within the United Nations Framework Convention on Climate Change (UNFCCC), which calls for reducing greenhouse gas emissions globally to two degrees Celsius below pre-industrial levels to avert the worst impacts of climate change (UNFCCC 2015). One component of the UNFCCC is the "technology mechanism" to support research, development, and commercialization of "climate technologies" to reduce the carbon intensity of industrial activities. The adoption of low- and zero-emissions energy sources such as solar, wind, and hydroelectricity economywide would significantly reduce GHGs from the electric power sector, which contributes approximately 27% of total GHGs in the United States, a close second in emissions share behind the transportation sector (EPA 2018b). Prioritizing decarbonization of electricity infrastructure is the quickest and most cost-efficient avenue to reducing economywide emissions (Larsen et al. 2021). Moreover, in planning a sequence of policy actions to reduce emissions across all sectors, it is necessary to pursue clean electricity production first, as decarbonization of the transportation and industrial sectors will require significant progress in electrification, and we can only achieve cross-sectoral emissions reductions benefits if the economy is undergirded by clean energy sources.

Despite near-unanimous international participation in the Paris Accord, the climate policy response in the US has been fragmented and incoherent. The Obama Administration's plan to regulate electricity sector emissions – the Clean Power Plan - suffered a defeat in the US Supreme Court. The US withdrew from the agreement under the Trump Administration, and Congress has not enacted any comprehensive environmental or energy legislation since the Energy Policy Act of 2005. Absent national leadership, state governments interested in pursuing climate and clean energy goals have filled in the void by enacting policies to support the development of renewable energy technologies, leading to some innovative advancements in reshaping regulation at the state-level to facilitate climate solutions. However, the gravity and scale of climate risk requires a nationally and internationally coordinated response, and not all states have the technical capacity or political will to engage in aggressive decarbonization. A patchwork response is wholly inadequate to mitigate and adapt to climate risk. Yet, at the same time, states are uniquely positioned to direct the activities of power companies by virtue of the historical development of the electricity regulatory regime in the US. In states whose economies are dependent upon fossil fuels and with utility companies resistant to rigorous renewable energy policies, policy regimes are less likely to include clean energy objectives, potentially spurring political conflict or rendering institutions less able to effectively respond to a changing policy environment. Policy analysts and climate advocates must map out the political and economic factors constraining states in order to advance climate and clean energy goals.

This dissertation explores these political tensions related to renewable energy policies and seeks to determine which political-economic factors induce state policymakers to adopt policies that would facilitate the transition toward clean energy sources. Concomitantly, this research is interested in exploring the factors that create institutional resistance toward clean energy policy change. The project focuses on policies supporting the growth of *distributed generation* technologies, or renewable energy projects that produce electricity at or close to the point of consumption, with rooftop solar systems as the most commonly known distributed technology. Examining the integration of distributed renewable energies across states is crucial for understanding the political dynamics that flow from technological change. A focus on state-level distributed generation policy allows us to examine how states navigate the technical and economic issues associated with distributed generation, and how the US system of federalism affects the technological systems in electricity production.

Some literature describes the electricity sector as *path-dependent* in that technological change is costly to implement, and regulatory frameworks are heavily characterized by *drift* due to the excessively incremental pace of policy change and the institutional resistance toward adapting to new technologies and evolving conditions. The growth of distributed generation reflects a paradigmatic shift from a centrally owned power grid to one that is increasingly decentralized. Electricity decentralization provides environmental and emissions benefits, but the transformation potentially threatens the conventional utility business model, posing a challenge to state utility regulators. How policymakers resolve the tension presented by decentralization, or resist policy change in light of the potential consequences of expanding distributed energy policies, is the central subject of this dissertation. Additionally, studying distributed renewable energy integration policy contributes to research on how policymakers balance environmental and economic priorities, and what political conditions are conducive for policy change in the electric power sector.

The project's guiding research question is: what can explain the variance in path dependence and regulatory drift across states' regulatory regimes, specifically in distributed generation policy? This research question can be divided into several empirical avenues. Why do states vary in their adoption of regulatory policies enabling the energy transition toward decentralized renewable sources? More specifically, what factors drive states to be more or less favorable toward expanding access toward distributed generation? This project suggests that to understand the sources of policy stability and change, policies must be connected to the broader institutional and economic context. Therefore, it is important to research the associations of political and economic trends with specific distributed generation policy outputs at the aggregate level. I propose that established policy regimes dictate the parameters of potential pathways of policy development and implementation, which is constrained by various regulatory and economic factors. Institutional choices and economic conditions could militate against advancement of renewable energy policies, or conversely, facilitate the expansion of clean energy technologies. In social sciences, this phenomenon is characterized as *path dependence*, in which future decisions are heavily determined by previous institutional choices. If path dependence hinders the adoption or modification of policy, *regulatory* or *policy drift* will result as regulatory regimes become increasingly unable to manage an evolving risk environment. These concepts are elaborated upon in the second chapter, while this chapter provides policy context for regulatory regimes governing the electricity sector as it relates to the development of distributed generation.

Political Vagaries of Technological Change in the Power Sector

Concurrently with the growing attention around the need to respond to climate risks, technological advancement in clean energy technologies is uprooting traditional business models in the energy industry. A key theme guiding this dissertation's perspective is that economic change seldom unfolds absent political conflict. Throughout the course of a state's economic development, industries periodically undergo paradigmatic changes due to technological innovation, hard market realities, and social/cultural attitudes, while public policy provides direction to satisfy certain objectives, such as the protection of the public interest or providing stability to the business community amidst an economic transition. As comprehensive change begins to ripple through an economic sector, the actors vested in the industry's continued operation respond by highlighting the costs incurred by moving away from the status quo. Technological and industrial change entails a shifting landscape of market participants, political coalitions, and models of earning revenues. These shifts tend to threaten the existing pathways of economic returns, sharpening political cleavages as a function of the financial risk imposed on established stakeholders and constituents. Hence, economic change poses a challenge to regulatory institutions; how do policymakers reconcile the demands of entrenched interests with the adoption of new and potentially contradictory policy priorities?

The political dynamics of technological change are evident in the electricity sector, where several forces are contributing to an acceleration of the systemwide transition from predominantly fossil fuel sources to renewable energy. Three primary trends are driving comprehensive transformation. First, technological advances have significantly lowered costs of development for renewable generation facilities in the 2010s, and renewables are increasingly competitive with fossil fuels; globally, solar and wind-produced electricity was cheaper than coal-fired electricity in 2019.[1] New technologies such as large-scale battery storage and smart grids are increasing the grid management capabilities for public utilities and system operators, enabling greater deployment of renewable generation systems. The expansion of renewable technologies exposes fossil fuel assets are exposed to considerable market risk. Electric utilities dependent upon legacy investments in fossil-fired generators stand to lose out as coal plants are shuttered in favor of low-emission energy sources.

Second, due to the proliferation of tools to modernize electricity infrastructure, technological progress has substantially increased the potential to integrate small-to-mid-scale energy systems onto the power grid. Policymakers have sought ways to facilitate the direct interconnection of renewable systems located on residential and commercial properties, and some states actively promote the installation of renewable projects through financial incentives. While the majority of electricity supply is still provided from privately-owned utility-scale facilities, generation is increasingly provided in larger part from projects located on the

[1] IRENA (2020), Renewable Power Generation Costs in 2019, International Renewable Energy Agency, Abu Dhabi.

distribution system, or the "customer's" side of the meter.[2] Falling technology costs have facilitated the installation of *distributed generation* technologies, especially rooftop-sited solar photovoltaic modules and also behind-the-meter battery storage, biomass projects, small-scale wind and hydroelectricity facilities, among others. Moreover, ratepayers of all political affiliations see distributed generation as an attractive proposition due to the cost-savings from offsetting their own energy consumption and achieving autonomy from their public utility.[3] The gradual movement from centralized to distributed generation alters grid economics and the revenue stream to electric corporations in significant ways; if customers can supply their own electricity through self-generation via distributed systems, the role of utilities as a service provider is potentially jeopardized. Prospective policies supporting the expansion of distributed generation markets could be met with political resistance due to the economic incentives driving public and private actors to preserve established arrangements. The status quo bias of institutions persists because actors would prefer to avert the perceived deleterious consequences to the energy system presented by comprehensive technological change.

Third, climate change has become a salient issue among the public, driving government officials at the state and local level to respond by exploring opportunities to promote emissions-free electricity generation. Environmental and clean energy advocates are pushing for economy-wide "decarbonization" to reduce greenhouse gas emissions to mitigate the deleterious effects of climate change, which involves taking fossil fuel-fired power plants offline. The push toward decarbonization sparks backlash from fossil-dependent utilities and the workforce dependent on

[2] Projects are considered "utility-scale" if they are greater than 10 megawatts in nameplate capacity. US Department of Energy, "Renewable Energy: Utility-Scale Policies and Programs."

[3] Public attitudes toward renewable energy, particularly rooftop solar, has grown more favorable throughout the 2010s. See Pew (2016), "The Politics of Climate: Public opinion on renewables and other energy sources." Pew Research Center.

the continued operation of fossil fuel assets. As a result of the current technological revolution, steadily rising social concern over climate change, and the increasing desire amongst citizens to have autonomy over their electricity use, several aspects of the long-standing policy regime governing electricity infrastructure are in the throes of transition. This project examines distributed generation policy in particular as one prong amidst a transforming energy system.

The accommodation of the energy transition requires the development of new regulatory frameworks that adequately attribute value to the environmental and long-term economic benefits of renewable energy. However, because flows of economic returns stand to lose out as the regulatory regime is reoriented around new policy objectives, institutions embedded in electricity system governance might resist wholesale changes that would upend the conventional utility business model. Policymakers are placed in the precarious position of articulating a balance between the new policy objectives of decarbonization and energy decentralization with the stakeholders and citizens that would bear the burden of a paradigmatic industrial shift; some actors face higher short-term costs from the energy transition, while other groups stand to benefit. Moreover, the effects of economic change are experienced to varying degrees based on geography and jurisdiction. State governments are uniquely positioned to regulate electricity infrastructure, and states vary in their industrial base, workforce composition, utility market structure, political culture, and regulatory frameworks. Because the federal government has abstained from enacting comprehensive energy policy in recent years and states have unique authority to govern retail utility markets, state governments have served as the fulcrum of policy activity in the electricity sector. The upshot is that public policy and implementation vary widely by state, leaving a patchwork of electricity regulation across the US, in which some states enable the energy transition at a more rapid pace than others.

This dissertation advances the hypothesis that the patchwork pattern of policies supporting distributed generation technologies is a result of varying degrees of political-economic *path dependence* in states' utility sectors, many of which are characterized by concentrated and centralized asset ownership as well as a heavy reliance on fossil fuel generation. These factors constrain states in implementing decarbonization and renewable energy policies to mitigate climate risks, resulting in *policy drift* as regulatory frameworks become increasingly unable to protect the public and infrastructure against social risks caused by climate change.

The remainder of the chapter will be devoted to contextualizing the policy conflicts surrounding the energy transition. First, I will provide a brief history and summary of the US policy developments in electricity sector regulation that are relevant for understanding political conflicts of the energy transition. Second, I will provide two illustrative cases that exemplify the policy conflict and highlight the intergovernmental arrangements and economic considerations that influence state policymaking. Third, I will provide an outline of the dissertation and discuss how this project can contribute to the field of research on the political dynamics of regulatory policy, especially in the context of electricity sector regulation.

Policy Context – Power Sector Regulation and Distributed Energy in the US

This section provides background on the evolution of the electricity industry, focusing on areas that are relevant for understanding policy conflicts arising from the shift toward renewable distributed generation. First, I summarize the federal legal and policy developments that shaped the institutional terrain of electricity governance in the US. Throughout the historical context of electricity regulation, the chapter weaves in discussion about the importance of state governments' ability to exercise authority in setting the state's energy policy direction, the role of public utility commission as the state utility regulator, and the how the federalist structure of the American political system has left a fragmented and incoherent regulatory regime across states. Second, I outline the challenges posed by fuel-switching from fossil-based resources to renewable energy and the integration of innovative technologies that introduce risk to the utility business model, particularly distributed generation. Laying out the regulatory framework governing the electricity system is a crucial step for understanding the barriers and drivers of pro-renewables policy adoption.

The Regulatory Compact: Governing Public Utilities

Prior to the enactment of 20th century federal statutes establishing a national framework for electricity market regulation and the parameters of state authority, there were no comprehensive standards instituting oversight over electric corporations. Additionally, most states did not create a regulatory apparatus to oversee the operation of public utilities or common carriers such as telecommunications companies during the 19th century. Utilities were instead regulated by municipal governments as a function of the necessity for electric companies to receive siting approval to build infrastructure (Hausman and Neufeld 2011). Power delivery lines could not be constructed without first acquiring rights-of-way within incorporated city territory, so municipal governments served as the *de facto* public utility regulator via their authority to confer franchise agreements, i.e., license to operate. Franchises emerged as the original mechanism of utility rate regulation, in which utility companies were allowed to earn profits from retail electricity under the auspices of municipal government, conditional upon certain obligations. Franchise agreements were structured as contract terms and specified the terms of operation to promote the public interest, such as price limits and access to utilities, but the stringency and number of corporate responsibilities varied greatly by municipality, and price limits were not strictly enforced (Hausman and Neufeld 2011). Franchise agreements typically lasted 20 to 50 years, securing the utility's incumbency and diminishing competition except in the largest urban centers (Troesken 2006).

Even in major cities with a more favorable environment for competition, the utility marketplace tended to favor a smaller number of service providers (Troesken 2006). The nascent power sector operated under loose municipal governance primarily because the authority of cities to enforce franchise terms was legally questionable. State constitutions did not authorize direct rate regulation from municipalities; therefore price limits were not treated as binding by electric corporations (Troesken 2006). Absent a coherent regulatory regime, there were no institutional safeguards to ensure accountability for the protection of ratepayers, and local government officials were especially susceptible to *capture,* a concept that holds the policy direction of public interest regulatory entities is strongly influenced by the interests of the regulated industry (Priest 1993, Levine and Forrence 1990, Bernstein 1955).[4]

The most significant problem that created the necessity for state regulation amidst a growing utility sector derives from the economics of infrastructure development. In many cases, privately-owned utilities were not able to recoup costs from expensive capital investments; assets such as transmission lines, distribution systems, and generation plants involve high fixed costs, whereas revenue from electricity sales would become appreciable only in the long run (Hausman

[4] Incidents of corruption in the utility industry among local elected officials via bribery and rent seeking is well documented (Troesken 1996, 2006; Joskow 1989). However, it should be noted that this corruption not perfectly align the definition of *regulatory capture*, since there was no legitimate oversight over the implementation of franchise agreements prior to state commissions authorized in statute. Capture implies there is a public agency whose actions are made in service to the business community, rather than the public interest. Chapter Two conducts a more thorough conceptual definition of regulatory capture.

and Neufeld 2011). Municipally owned utilities also provided electricity service, and while this allowed for a greater degree of control over enforcement of franchise agreements, public ownership could not mitigate the problem of prohibitive capital costs on its own. The lack of market competition was exacerbated by the capital-intensive nature of electrical infrastructure, as utility companies are incentivized to continue operations to remain commercially viable, despite the fact they are unable to recover fixed costs from electricity sales in the short term. Additionally, technological innovation drove energy costs down throughout the latter half of the 19th and early 20th Centuries, further inhibiting the utility's ability to reap profits.

One consequence of high up-front costs and technological innovation was reduced access to the utility marketplace, as bigger players came to dominate the electricity market through large capital investments and to retain those assets by simply recovering operating costs. Another consequence was that the reliability of service suffered, as revenue went toward perpetuating the utility's operation rather than improve and replace aging infrastructure. The absence of local authority, state or federal oversight, and prohibitive capital costs resulted in a gradually more concentrated electricity system, served in larger part by a smaller number of private actors.

The disincentive to prioritize utility maintenance served as the impetus for the creation of state regulatory commissions in the early 20th century, which established a method of regulating utility business's rates to promote certain objectives, including safety, reliability, expanded service access, etc. Through federal case law, state commissions are obligated to ensure that rate-regulated industries receive a "fair" return on investment.[5] They are required to determine three essential components in calculating rates: (1) the utility company's capital investments, or "rate base," (2) the utility's operating costs, and (3) a reasonable return based on the utility's total debt

[5] *Smith v. Ames 1898* (169 US 466)

and financial investments (Hausman and Neufeld 2011). Commissions operate as a quasi-judicial administrative body; commissioners hear testimony by utilities in “rate cases”, in which utilities present evidence to justify investment decisions, the costs of which might then be incorporated into the rate-of-return (Bonbright 1961). The total value from the three above elements is termed the “revenue requirement” that utilities are owed, which is recovered through customer bills. A simplified version of the revenue requirement formula is written below:

Revenue Requirement = Rate Base + Operating Costs + Rate of Return

Utility profits then came to be a function of regulatory commission procedures as the majority of states adopted public utility commissions, or PUCs, from 1900 to 1920[6] (Hauman and Neufeld 2011, Priest 1993). The new regulatory framework had the effect of entrenchment and reaffirmation of the utility’s exclusive service territory, insulating established companies from competition. Further, because investments across all segments of the supply chain are factored into the rate base and rate of return, this regulatory construct ensured that the electrical power industry would be vertically integrated, with companies maintaining ownership over the generation, transmission, and distribution of electricity. These developments solidified the bedrock of the *regulatory compact* between the government and utility operators; government regulation essentially protects the monopoly status of utility companies in exchange for the provision of safe and reliable service at just and reasonable rates to the consumer.[7] The regulatory compact and revenue requirement eventually presented unintended consequences to the power sector, as it encourages utilities to build more infrastructure and sell more electricity

[6] States initially relied on regulatory commissions for the regulation of railroad rates and came to be named “public utility commissions” more frequently as states brought more public service industries such as electricity and telecommunications into the regulatory fold. Not all states name their regulatory commissions “PUCs”; some are designated the Public Service Commission (PSC), State Corporation Commission (SCC), or similar variants.

[7] *The Binghamton Bridge*, 70 U.S. 51 (1865). Also see: Girouard (2015), “How Do Electric Utilities Make Money?” Advanced Energy Economy, 23 April 2015. https://blog.aee.net/how-do-electric-utilities-make-money

without regard to systemwide efficiency. Hence, energy conservation and innovative technologies are inhibited by the very regulatory construct that affords utilities to operate. This point will be fleshed out further in the next section and frequently revisited throughout the dissertation.

While the emergence of PUCs created a policy mechanism to promote sound investments in the public interest, agencies were initially unequipped to correct problems that arose out of rapidly increasing market concentration shortly after the initial period of states authorizing the creation of utility commissions. The natural monopolization of public utilities became more obvious with the development of regional transmission networks and emergence of utility holding companies. The progression of transmission technology in the early 20th century meant that utilities could interconnect multiple generators across large geographic swaths crossing state boundaries, while service territories were previously constrained by proximity to a single generator. This period was also characterized by growth in electricity demand concurrent with a rising industrial sector, driving the expansion of electricity infrastructure. From 1920 to 1935, electric utilities sought to consolidate under a new financial tool: holding companies, which held key advantages. Holding companies spanned nationally and were advantageous for attracting substantial investments to grow utility businesses, and they provided technical expertise to subsidiary utilities.

The problems with holding companies were significant; not only were they ripe ground for securities fraud, but they also were convenient avenues for circumventing state regulation. They are not subject to state regulation, allowing the holding company to include services in the proposed rate base without consequence, since the state would risk the subsidiary's rate-of-return if the PUC rejected rate increases (Hausman and Neufeld 2011). The consolidation of electric utilities and the building-out of transmission infrastructure resulted in vertically integrated multi-state entities in which a few utility holding companies controlled most utility operations throughout the US. Ultimately, rate-of-return utility regulation would be reformed to empower state commissions following the 1929 stock market crash and subsequent policy developments.

State-Centric Utility Regulation: PUHCA and PURPA

States would become the central actor in power sector regulation with the passage of the Public Utilities Act of 1935. Fraudulent business practices amongst utility holdings companies in the 1920s would lead to financial bubbles and mass declarations of bankruptcy, severely damaging subsidiaries' ability to provide reliable electricity service at an affordable price (Eisner et al. 2006). The Great Depression drained the capacity for operating companies to build new infrastructure to expand service access, as well. In order to address the problems endemic to holding companies and to exercise control over energy supply, Congress moved to adopt the Public Utilities Act of 1935, which contained two major legislative actions. Title II of the Public Utilities Act created the Federal Power Act (FPA), which established the parameters of federal jurisdiction to oversee interstate trade within wholesale electricity markets and authorized states to regulate retail electricity sales within their boundaries. The FPA amended the Federal Water Power Act of 1920, which had created the Federal Power Commission (FPC) as the agency regulating nonfederal hydroelectric facilities (CRS 2017). With the passage of the FPA, the FPC now exercised oversight over wholesale markets, and would later be renamed as the Federal Energy Regulatory Commission (FERC).

More significantly for this project is Title I, or the Public Utility Holding Company Act (PUHCA). The PUHCA authorized the Securities and Exchange Commission (SEC) to implement tools to essentially break up large multi-state holding companies. Electric corporations faced new requirements to be associated with a single physically interconnected utility system. Additionally, companies were not allowed to carry out mergers or acquisition unless they receive regulatory approval finding that the consolidation would serve the public interest (Hausman and Neufeld 2011). Utilities were similarly disallowed from owning assets in non-utility business unless the business was "economically necessary or appropriate" for electric service provision, minimizing their market power.[8] These statutory requirements afforded a greater degree of retail market control by PUCs, as the utility industry was now subject to rigorous monitoring by the federal government. Holding companies could no longer subvert state regulatory frameworks, because the scope and scale of utility business faced geographical and jurisdictional constraints that were nonexistent while the groundwork of electricity infrastructure was laid during the industrial revolution (Eisner et al. 2006). The PUHCA had enabled state oversight of privately-owned utilities to an unprecedent degree and strengthened the regulatory compact between states and utilities.

It should be reiterated that non-private utilities public power provision by municipal governments expanded alongside growth of the electricity sector, and federal power agencies such as the Tennessee Valley Authority were created as part of the Roosevelt administration's New Deal to build transmission towers, construct generation projects, and expand electrification into rural areas (Troesken 2006, Eisner et al. 2006). Another outgrowth of the New Deal-era focus on extending service access was the creation of the Rural Electrification Administration, which spurred the growth of electric cooperatives. Electric cooperatives are associations of ratepayers in predominantly rural areas that purchase electricity from regulated providers. A

[8] Public Utilities Holding Company Act 1935, P.L. 74-333

common utility cooperative structure involves distribution cooperatives, which own the distribution lines that deliver electricity to end-uses such as households, and generation/transmission cooperatives, which own power plants and higher-voltage transmission facilities that potentially cross state boundaries. Distribution cooperatives purchase electricity from generation/transmission cooperatives on a wholesale basis, making them subject to federal regulation under the FPA (Rudolph and Ridley 1986, Eisner et al. 2006).

State governments do not exert as much influence over the activities of publicly owned utilities and cooperatives, as those entities have a greater deal of autonomy from PUCs, though the scope of jurisdiction over cooperatives and municipalities varies by state. Private or investor-owned utilities (IOUs), on the other hand, are the primary subject of state regulatory commissions, and historically, IOUs serve the bulk of electricity consumers in the US.[9] This project proposes that the class of ownership over electric infrastructure matters in terms of explaining the variation of energy policies at the state level. Given the revenue model that incentivizes major utilities to invest in large transmission and generation projects, we might expect investor-owned utilities to be more effective at arguing against distributed generation in policy venues. Whether states with higher proportions of private ownership are more constrained in their decision making to adopt grid-transformative policies is a central research question of this dissertation and is explored in detail in Chapter Four.

Following PUHCA, the next major relevant policy juncture did not occur until the Carter Administration with the Public Utility Regulatory Policies Act of 1978, or PURPA. PURPA was significant for electricity sector governance for two broad reasons. First, the enactment of PURPA marked the first federal action designed to directly support the development and

[9] EIA 2017. Investor-owned utilities provided 72% of the US's electricity supply in 2017. Energy Information Administration, 15 August 2019. https://www.eia.gov/todayinenergy/detail.php?id=40913#

consumption of renewable energy. While the legislation was couched as a means to increase the US's energy production sovereignty amidst the Organization of the Petroleum Exporting Countries (OPEC) embargoes of the 1970s and other energy crises, the law effectively incentivized the production of small-scale renewable-sourced electricity (Eisner et al. 2006). The OPEC embargoes had introduced an exogenous shock by dramatically rising fuel input costs, placing utilities in a vulnerable position (Isser 2015, Watkiss and Smith 1993). Moreover, environmental issues had rapidly gained salience in American politics in the 1960s and 70s; litigation arising out of the Clean Air and Water Acts to contest the construction of new generation plants had exerted political pressure to reduce reliance on fossil fuels and nuclear energy (Watkiss and Smith 1993; Duffy 1997). This is significant because, as alluded to in the discussion on the regulatory compact, the rate-of-return formula repels utilities from adopting innovative technologies that would reduce consumption from fossil fuel plants, as electricity sales from utility assets factor in the cost-of-service calculation. Absent regulatory reforms, public policy is needed to push renewable sources into the electricity sector.

Second, PURPA introduced competition into electricity markets with the creation of a new class of provider separate from traditional rate-regulated utilities: independent power producers, or IPPs. PURPA directed PUCs to require utilities to purchase electricity from "Qualifying Facilities", or QFs, owned by IPPs. QFs are located on the distribution system within IPP property, often for the purposes of self-generation to satisfy the property owner's energy needs without relying on power from the utility system. QFs fall into one of two categories: (1) small renewable power production facilities that includes hydroelectricity, wind, solar, biomass, waste energy, and geothermal, or (2) cogeneration, or combined heat-and-power (CHP) projects, in which industrial facilities with on-site electric generation use the heat by-product from generation to direct thermal energy toward heating for buildings or heating districts. Commissions are tasked with setting rates at which the utility purchases QF-sourced electricity, which can either be negotiated between the utility and IPP or set at the "avoided-cost rate." The avoided-cost rate is calculated by the PUC, which is determined by factoring in the costs of infrastructure maintenance and service provision *not* required by the utility by virtue of renewable QF purchases. PURPA effectively set the avoided-cost rate as the default rate utilities must pay distributed generators. With the insertion of QFs into the electricity market, centrally operated utility-scale power plants no longer maintained a complete stranglehold on electricity supply. Coal assets would have to compete with renewable-sourced QFs located outside of the utility-owned transmission and generation infrastructure.

PURPA would prove to serve as the first step towards enabling a suite of state policies encouraging the development of renewable projects located on the distribution system. Because the law injected competition into completely vertically integrated utility markets, QF contracts were the initial mechanism to effectuate state level activity that would culminate in systemwide changes; as on-site generation technology evolved, independent power producers proliferated, and states were able to capitalize on the integration of renewable systems by restructuring their energy market in favor of utility competitors. Federal policies would also seek to foster competition with the creation of interstate electricity markets and by providing direction to states on how to address competitive electricity providers. The next section describes the succession of transformative policies, their associated flashpoints, and how the policy conflicts emerging out of a transitioning electricity system are relevant to understanding the path dependence shaping contemporary issues surrounding the regulation of distributed resources.

Electricity Restructuring and State Distributed Generation Policy

The enactment of PURPA can be considered the critical juncture that forced a wedge into the centralized power markets of the US, in that it was the first major federal policy to encourage consumption from alternative sources of energy, in terms of both alternatives to fossil fuels in renewable energy sources and systems located on customer, rather than utility, property. Customer-generators, or ratepayers that produce electricity from systems located on customer property "behind the utility meter" would become a new focal point in a policy regime designed to promote the use of on-site generation.

Policies to support distributed energy advanced in the context of a national policy shift that would fundamentally alter the structure of the electricity system in the late quarter of the 20th century. The federal government became the overseer of electricity markets in the United States, and a series of policy changes enabled states to pursue more decentralized models of power delivery. However, these changes progressed on an incremental basis, leaving the IOU-centric regulatory regime intact. PURPA secured the revenue stream for small IPPs, enabling states to devise competitive bidding processes for the construction of new infrastructure (Watkins and Smith 1993). Over the decade following PURPA's passage, evidence accumulated that the long-standing bulk power system faced significant barriers in the formation of competitive wholesale markets, as vertically integrated utilities still wielded market power through its ownership of generation and transmission facilities. While PURPA had granted an opening for competitive providers, they might still be locked out of grid access due to geographic variation in utility regulation and transmission access; further interventions would be required to ensure competitive providers had the means to deliver electricity to end-users. The Energy Policy Act of 1992 granted FERC oversight jurisdiction over transmission projects through the federal government's constitutional authority to regulate interstate commerce. FERC proceeded to develop the open access transmission tariff (OATT), requiring utilities to file OATTs allowing grid service access on a non-discriminatory basis to wholesale electricity providers.[10] FERC also imposed rules to "functionally unbundle" the transmission, generation, and distribution activities of public utilities by requiring standards of conduct to foster independent operation for each phase of the delivery system in an attempt to partially mitigate monopolistic market concentration.[11]

Electricity restructuring would not end with open transmission access. In 1999, FERC issued regulations that encouraged the formation of Regional Transmission Organizations (RTOs), which are also named Independent System Operators (ISOs).[12] RTOs are quasi-governmental independent entities that manage grid supply and facilitate wholesale electricity sales, and they maintain ownership of and operate the transmission system once the RTO's formation is approved by FERC. RTOs were adopted as an instrument intended to bring electricity markets closer to optimal efficiency. Induced competition could also drive a more efficient allocation of energy resources, increasing system reliability and depressing ratepayer costs (Hoecker 2019). Additionally, RTOs could provide environmental benefits, as the expanded access opened the transmission system to renewable energy developers, allowing market participants to switch providers and reduce reliance on fossil fuel-generated electricity (Stafford and Wilson 2016). FERC would improve market rules in 2003, when it required RTO

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[10] FERC Orders 888 and 889 established OATT requirements for public utilities. 'Non-discriminatory' means that electricity supply must be selected on a 'fuel-neutral' basis, in that no specific fuel source should receive favorable treatment over the other; the least-cost and most reliable resources would be selected through bidding procedures. See https://www.ferc.gov/sites/default/files/2020-05/rm95-8-0aj.txt

[11] FERC Order 889 instituted standards of conduct for interstate transmission.

[12] FERC Order 2000 established the mechanism for the creation of RTOs. https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf

utilities to file tariffs adopting standardized interconnection procedures for systems providing wholesale service, which must be at least 20 megawatts (MW) in size.[13] FERC adopted regulations governing the interconnection of small systems (< 20 MW) two years later, named the Small Generator Interconnection Procedures (SGIP), which would be an informative model for states devising their own interconnection standards for the regulation of integrating distributed systems.[14] The standards' intent was to improve and maintain reliability through the integration of new resources, but they also served as a policy mechanism to provide leverage to renewable generators in accessing the electricity grid.

The national policy shift indicates a growing acknowledgement among policymakers and utility industry leaders that a power system inhibited from market competition may be suboptimal for efficiency, reliability, and affordability. While the federal regulatory context governing wholesale transactions evolved rapidly, state government approaches toward competition varied greatly. Some states would respond to the 1992 Act and subsequent FERC orders by restructuring their retail market entirely by allowing customers that cross a minimum demand requirement to select their electricity provider.[15] Utilities in several states fulfilled the intent of Order 2000 by consolidating under RTOs, placing control of their transmission systems under an independent system operator. Because certain aspects of the FERC orders were not compulsory, many states opted to retain the existing regulatory structure to insulate IOUs from competition. Furthermore, the suite of national policy changes maintained the PUCs'

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[13] FERC Order 2003 established standard interconnection procedures for large systems. https://www.ferc.gov/sites/default/files/2020-06/order-2003.pdf

[14] FERC Order 2006 established standard interconnection procedures for small systems, which have been periodically revised since adoption. https://www.ferc.gov/sites/default/files/2020-05/20050512110357-order2006.pdf

[15] Electricity restructuring has been elsewhere termed "deregulation" because it removes the regulatory construct of vertical integration over all phases of electricity service, but this project prefers "restructuring" as a more accurate term, because the cost-of-service model of rate regulation still holds for utilities in states that have restructured the market for retail competition, despite the fact that the utility is not guaranteed a monopoly.

jurisdictional purview over retail transactions and, by extension, their authority to regulate the distribution of electricity through IOU-built infrastructure. PUCs' differences in their orientation toward utility competition would result in divergent distributed generation (DG) policy frameworks across states.

The patchwork pattern of state level DG policy materialized shortly after the enactment of PURPA, in which states began exploring two policy tools to boost the deployment of DG systems and renewable energy within retail electricity markets: (1) interconnection standards, and (2) net metering programs. *Interconnection standards* establish the technical and procedural requirements that prospective customer-generators must satisfy in order to connect generation devices to the utility system, and generally apply to smaller systems designed for residential or commercial use, though a few state rules apply to larger systems for industrial use. Interconnection rules might specify requisite technologies, such as maximum voltage, system size capacity, and sources of energy, or lay out a process by which stakeholders can carry out dispute resolution. Standards frequently include liability insurance requirements and interconnection fees. The purpose of PUC-devised interconnection regulations was to standardize the process for DG interconnection statewide; prior to state rules, interconnection requests would go purely through the utility, a process that may lack transparency and consistency as utility companies would seldom coordinate in the development of coherent standards. Coherent statewide standards would not be instrumental for protecting system reliability as increasing amounts of DG was interconnected, but it also afforded the state a mechanism to encourage the penetration of distributed renewable energy on the power grid.

States tended to codify net metering policies in tandem with interconnection standards, as the interconnection of net-metered systems would require a standardized regulatory framework similar to the reasons listed above. *Net metering* policies provide compensation for electricity generated on customer property, or "behind-the-meter." For example, if an electricity customer installs a photovoltaic rooftop solar device and the device produces more electricity than the property draws from the utility system, the net excess electricity is exported to the power grid. The electricity exported can then be credited to the customer-generator's utility bill to financially offset the customer's electricity consumption. The conventional program design for net metering schemes highlights a more robust supportive policy environment for DG than PURPA, as many net metering policies compensate net excess generation on a kilowatt-hour (kWh) basis at the full retail rate of electricity. This is significant because the retail rate is often substantially higher than the avoided-cost rate, the default rate utilities must pay IPPs for QF-sourced electricity. However, much in the way that states approached the implementation of rollover credits differently, not all states elected to compensate net metered systems at the full retail rate. Some policies compensated net excess electricity at the avoided-cost rate, while others only allowed the offset of electricity use without compensating grid exports.

While a few individual utility companies offered net metering programs for their customers in the years after PURPA, Minnesota would be the first state to enact net metering and interconnection policies in 1983, and several states, such as California in 1996, would follow in the remainder of the 20th century to support the development of distributed generation (NREL 1998). In service of state goals to promote clean energy, net metering would be complimentary with an emerging policy: renewable portfolio standards (RPS), which directs public utilities to provide a minimum percentage of electricity sales from renewable sources. Some RPS statutes require a minimum capacity procurement – or carve-out – from DG systems, or specific technology type such as distributed solar (DSIRE 2020). Because state net metering policies are utility directives, net metering assists utilities in implementing RPS requirements by instituting a clear pathway for the interconnection of distributed renewable energy. It should be noted that RPS poses a more stringent regulatory environment for utilities than net metering, as it entails a mandate that potentially requires the closure of fossil fuel plants to meet the targeted electricity portfolio. Mandated plant closures would generate political resistance amongst the utility industry. Hence, states with RPS were more likely to adopt net metering statutes. Statewide net metering programs were more ubiquitous, but the mechanisms for implementation were not consistent, and were not always paired with interconnection standards to clarify the regulatory process for customer-generators (Schelly et al. 2017, Stafford and Wilson 2016). Nevertheless, net metering programs helped drive residential and commercial adoption of DG technologies, rooftop photovoltaic (PV) solar systems in particular (CRS 2019).

The federal government would look to the omnibus Energy Policy Act of 2005 in seeking to address the patchwork pattern of policies supporting distributed generation across states. Specifically, the act amended PURPA by directing states that have not established net metering programs to direct its utilities to adopt net metering or a similar scheme for utilities to compensate net excess generation.[16] While most states eventually responded by adopting a variant on net metering, the law did not advance a clear standard to address the inconsistent program design and implementation methods employed from the myriad state approaches to compensating net excess generation from distributed systems. Several political and economic factors militate against state policymakers supporting distributed renewable energy too emphatically.

[16] Energy Policy Act of 2005 (P.L. 109-58; Subtitle E, Section 1251)

In part, lag on DG policy is explainable as a function of political resistance toward renewable energy sources due to their intermittency. Solar and wind technologies are considered variable energy resources (VERs) due to the fact that generation output is a direct function of weather conditions; more sunlight exposure means greater production of megawatt hours, and likewise for wind patterns (Jones 2017). Weather fluctuations could result in either overgeneration, requiring curtailment of generation resources, or alternatively, resource inadequacy in the case of cloud cover or stagnant winds. To buffer against intermittency in the latter case, grid operators prefer to maintain conventional generation that produces electricity output on a constant basis throughout the day. Coal and nuclear are referred to as "base load capacity" sources of generation, since they serve electricity demand continuously, providing a stable floor of power provision regardless of exogenous factors.[17] Because solar and wind are VERs, policymakers balk at the notion of reorienting the grid around renewable technologies. However, proper management of VER integration can ultimately lead to greater system efficiency and cost savings to ratepayers (Lovins 2017). Political opposition to renewable facilities may also take the form of place-based resistance; community residents might object to siting wind or solar projects for aesthetic purposes, or notions that large renewable facilities disturb the character of the land (Yi and Feiock 2014).

While there is a multitude of dimensions comprising political attitudes toward policies supporting renewable energy development, this project analyzes a problem specific to distributed generation to analyze institutional resistance toward expanding DG access: the problem of cost-shifting and cross-subsidization. These issues are discussed in the section below.

[17] See Energy Information Administration, Glossary: "Base Load Capacity" https://www.eia.gov/tools/glossary/index.php?id=B

The Policy Problem: Cost Shifts and Cross-Subsidization

Utility stakeholders and ratepayer advocates raise the issue of cost-shifts as a potentially regressive consequence of policies that encourage greater amounts of distributed generation on the power grid. *Cost-shifting* refers to the fact that DG customers, under a retail rate compensation scheme offered by net metering, are able to circumvent fixed charges through the self-generation incentive, leaving non-DG customers responsible for paying them. Recalling the rate-of-return construct for determining utility rates, utilities are granted the ability to recover capital investments through electricity rates, which are factored into customer bills through fixed charges. PUCs and utilities devise separate charges to recover costs of constructing and maintaining transmission equipment, distribution equipment, along with other charges to fund grid operation. These costs are embedded in the utilities' regulatory revenue requirement, meaning that utility system upkeep is dependent upon the recovery of grid charges through electricity sales, which give way to DG as deployment grows.

While it is a given that net metering incentivizes DG customers to supply their own electricity, induced effects on utility economics are less obvious. Retail rate compensation allows a DG owner to totally offset their electricity consumption if their on-site system is capable of doing so, leaving fixed charges unpaid and utility capital costs unrecovered. To recoup capital and operating expenses that would otherwise be recovered through a customer bill, the utility may be forced to file a request for a rate increase at the PUC by raising fixed charges. The end result is that non-DG owners would face higher electric bills to pay into transmission and distribution infrastructure as a utility service territory experiences increasingly higher penetrations of DG systems. The main point of contention against policies supporting DG deployment is that DG systems are predominantly "grid-tied," meaning that they are integrated into the utility system. As of 2019, approximately 91% of all distributed generation capacity in the US is grid-connected.[18] Direct interconnection to the utility system is necessary because the majority of DG owners, despite the fact that they benefit from self-generation, cannot be totally self-reliant. DG customers still rely on transmission and distribution infrastructure to import power from the power grid when on-site generation is not productive enough to meet their property's demand. Moreover, DG customers would not be able to export net excess electricity if they were not interconnected to the power grid. In effect, cost shifts amount to a disproportionate incursion of costs by one group of consumers as a negative network externality deriving from the financial benefit of another category of consumers. This is why cost-shifting is used interchangeably with the term *cross-subsidization*; regular electricity consumers are forced to pay a greater share of infrastructure costs, which a DG customer may offset, as retail electricity sales decrease relative to self-generation, despite the fact that self-generators are buttressed by the power grid to some extent.

The concern over non-DG ratepayers paying for infrastructure that DG owners use is primarily grounded in two underlying norms guiding utility rate design: (1) cost causation and (2) equity. Both principles of rate design involve the issue of "just and reasonable" cost allocation amongst customers, both within and across residential, commercial, and industrial rate classes (Bonbright 1961). First, cost causation refers to the intent to reflect the true cost of using electricity infrastructure in consumer bills (Eid et al. 2014, Geffert and Strunk 2017). Built into cost causality is the idea that the ratemaking process should devise efficient price signals to drive

[18] By definition, all net metering systems are grid-tied. See https://www.eia.gov/electricity/data/eia861m/

generation investments, but is has been argued that the arrangement in which utilities purchase exported power is inefficient in the sense that DG customers are being "overcompensated" due to net excess generation's value set at the retail rate (EEI 2013, Eid et al. 2014). Utility stakeholders question the wisdom of paying retail prices for distributed generation when those prices would otherwise reflect transmission and distribution infrastructure costs outside of a net metering program.

Second, equity refers to the need for fairness in allocating costs among ratepayers; rates should not impose disproportionate burdens or cause "undue discrimination" against any specific customer types (Geffert and Strunk 2017: 37, Castaneda et al. 2013, Bonbright 1961). Under the conventional cost-of-service framework based on volumetric electricity sales, no mechanism has been established to distinguish DG customers from non-DG customers as a unique rate class. In other words, while commercial ratepayers may pay different rates than residential ratepayers, net metering participants do not pay at different rates than nonparticipants. This reality has led some ratepayer advocates to argue for reforming rate design around net metering in such a way that prevents cross-subsidization. By filling the gap in a utility's revenue requirement, nonparticipants effectively subsidize the infrastructure costs for net metering participants, assuming that the conventional rate design is in place. Moreover, residential customers who install distributed energy devices are typically in higher income brackets; lower-income customers do not have the financial means to purchase and maintain a rooftop solar PV system, for example (Johnson et al. 2017). If higher income customers are able to lower their energy costs with net metering, the costs of which are displaced on lower-income ratepayers, the arrangement is regressive in practice.

Inequity and inefficiency are the primary arguments advanced to reform net metering, but some see the policy as having even more pernicious long-term effects. The expression “utility death spiral” has been employed to describe the situation in which utilities lose revenue to distributed generation, driving utilities to raise prices to recover costs, which drives customer adoption of DG to lower their energy burden, forcing utilities to further increase rates potentially beyond the point of economic viability, ultimately cratering utility service (Castaneda et al. 2017, Felder and Athawale 2014, Costello and Hemphill 2014). This negative feedback accelerates as DG reaches high market penetration levels and utilities are unable to recoup capital and operating expenses through sales volume alone.

There are two reasons to doubt the catastrophic long-term predictions of the ramifications of losing utility revenue out to distributed generation. The first reason derives from the intermittency characteristic and technological limitations of renewable energy sources. Since behind-the-meter generation is usually insufficient to meet residential property needs on an around-the-clock basis, many net metering participants are not net sellers of electricity and pay electricity bills just as non-DG customers do. In New Mexico for example, a study of the state’s net metering participants found that only a third of rooftop solar owners produced more electricity than they consumed, while the other two-thirds of net metered DG customers were net buyers of electricity (Blank and Gegax 2019). Further, net buyers paid 90% of their full cost of utility service. The majority of fixed costs are recovered from the DG customer class.

Second, there is evidence for cross-shifting driven the integration of DG systems, but at least thus far, studies quantifying the magnitude of cross-subsidization are mixed. The change in marginal cost per kilowatt-hour of electricity produced experiences an increase in certain service territories for non-DG customers in the short-term, and the direction and degree of change in cost depends on many power system characteristics such as network density, dominant categories of customer load class, intensity of demand peaks, modern grid functionality such as distribution system interoperability, and (Satchwell et al. 2014, Eid et al. 2013, Picciariello et al. 2015). The primary determinant for DG raising short-term costs is the market penetration level; integrating swaths of rooftop solar at a rapid pace would incur a more substantial increase in utility financial risk (Satchwell et al. 2015; Picciariello et al. 2015). Moreover, aggressive utility programs to increase deployment of energy efficiency programs and residential solar PV raises bills for non-participating ratepayers, and even savings for DG customers would rise over a longer time span (Satchwell et al. 2018). Other research finds that, in many cases, grid-tied DG raises grid costs for other customers by a nonsignificant amount. A study of distributed solar within the Pennsylvania-Jersey-Maryland (PJM) RTO found that, even in aggressive adoption scenarios, nonparticipant customer bills increase only by 2% or less (Johnson et al. 2017)[19]. While the term “utility death spiral” dramatically overstates the problem posed by DG integration, most benefit-cost analyses recognize that some degree of cost shifting and/or cross-subsidization does occur as a result of net metering policies (Boreo et al. 2016, Satchwell et al. 2018, Picciariello et al. 2015, Johnson et al. 2017).

To restate the project’s impetus, the universe of potential influences affecting DG policy orientation among state policymakers and PUCs is the central subject of this dissertation. Literature on renewable energy and electricity policy is replete with studies on the financial effects of net metering and DG integration, but other research seeks to understand how the political system shapes the regulatory landscape constraining renewable technology adoption. The question of why state governmental institutions vary in their disposition toward regulatory

[19] Johnson et al (2017) defines a high adoption scenario of distributed solar comprising a total of 5% of aggregate generation load.

change has inspired much speculation. Do theories of regulatory capture explain state reticence toward DG integration? Is it the case that some states' electricity corporations are more politically embedded into the utility regulatory subsystem than other states? Do some states' utility industries wield disproportionate political power in state legislatures or in utility commission proceedings? Is it simply the case that input costs such as fuel prices levy a more stringent burden on some states' utilities than others as a function of the regional geography's resource portfolio? To illustrate the issues at stake and to bring the dissertation's research question into focus, I now turn to examine two states and their contrasting trajectories in supporting DG integration through policy actions.

Minnesota: Community Renewables, Interconnection Standards, Value of Solar Tariff

Over the past decade, Minnesota has exemplified states exercising initiative in advancing solutions to the policy problems arising from net metering and distributed energy integration after experiencing a long period of relative stagnation. The state was the first to establish mandatory net metering for investor-owned utilities, municipal utilities, and electric cooperatives in 1983, but Minnesota made scant adjustments to net metering requirements in successive legislative sessions.[20] Following the Energy Policy Act of 2005, many states turned to review their net metering policies to evaluate the effectiveness of net metering in fulfilling state policy objectives of encourage DG deployment.

Studies of Minnesota's net metering policy found components of the original statute lagging behind other states in the development of a modern policy framework, with several areas in need of updates to align with state best practices for compensating DG (Doris et al. 2009).

[20] Database of State Incentives for Renewables and Efficiency (DSIRE), https://programs.dsireusa.org/system/program/detail/282

IOUs were only required to offer retail rate compensation for devices up to 40 kW in system size capacity; beyond the 40kW limit, utilities would only offer avoided cost rate compensation for net excess generation. Low system capacity limits inhibit the growth of DG markets, particularly in the commercial and industrial sectors. Moreover, systems eligible for retail compensation could only receive bill credits on a monthly basis, while other jurisdictions allowed bill credits to rollover for a 12-month period or indefinitely. Another significant limitation was the inability to aggregate demand to receive net metering credits for electricity produced across multiple meters. Most net metering laws, including Minnesota's required compensation at a single parcel of property or building, but the limitation hampers the ability for larger electricity consumers to reap the benefits of a behind-the-meter renewable project (Farrell 2015). For example, there might be several electric meters located across multiple facilities on agricultural lands or government buildings, which may be located within a single lot or spread across contiguous properties. The original net metering framework afforded little flexibility for agricultural or institutional customers in aggregating their demand to receive renewable electricity, despite the possibility that a renewable project may be located on an adjacent property. The implicit prohibition on meter aggregation for interconnecting DGs derived from the old regulatory compact protecting utility monopoly status, and it eventually became out-of-step with technological innovation and a growing renewables market.

A critical juncture emerged in 2013, when Minnesota's legislature sought to comprehensively resolve regulatory barriers on the state's development of distributed generation. The omnibus energy bill HF 729 addressed a number of limitations to DG deployment.[21] The

[21] Minnesota House File 729, Omnibus jobs, economic development, housing, commerce, and energy bill. Secretary of State, Chapter 85, Adopted 23 May 2015. https://www.revisor.mn.gov/bills/bill.php?b=House&f=HF0729&ssn=0&y=2013

legislature directed the Minnesota PUC to raise the system size limit from 40 kW to 1 MW, significantly increasing the demand floor for customer-generators. The act also authorized utilities to approve aggregate net metering requests, explicitly allowing DG customers to aggregate contiguous loads and easing the ability for public institutions and agricultural property owners to utilities energy conservation and promote renewable electricity generation across their facilities.

Concomitant with the adoption of aggregate net metering, the legislature advanced a related policy tool in HF 729: shared renewable energy access, known in other states as community solar programs. Many electricity users who want to reduce consumption from the utility grid and promote renewable energy might be unable to install a DG project on-site; there might be inadequate rooftop space for siting solar PV modules for a residential customer, or a commercial customer might be located in a dense urban area with little room to construct a new DG project. Tenants within multifamily housing do not have the option of offsetting electricity use with on-site generation. Additionally, DG equipment presents high upfront costs to the consumer, leaving low-income households with diminished capacity to acquire their own DG (CCSA 2019). Shared renewable energy programs enables customers without DG site-compatible properties to receive electricity from distributed renewable facilities, significantly expanding the opportunity to utilize DG beyond on-site customer-generators. Programs work like a subscription service, in which participants opt-in to receive a portion of electricity produced by a renewable project located on the utility's distribution network (Feldman et al. 2015). To advance shared renewables opportunities in light of regulatory, technical, and financial hindrances, the Minnesota legislature directed the state's largest utility, Xcel Energy, to file a Community Solar Gardens (CSG) program with the PUC. Xcel is required to purchase all energy from CSG facilities participants at a rate that is either (a) established under a tariff approved by the commission, or (b) at the retail rate, effectively enrolling CSG participants into net metering. Since its adoption, Minnesota's is the fastest-growing community solar program in the United States: the first megawatt of cumulative capacity went operational in 2017, and by December 2020, 757 MW is operational (Farrell 2020).

In addition to the positive adjustments to the state's DG policy framework, industry stakeholders and regulators scrutinized another regulatory barrier: interconnection standards. HF 729 had required utilities to develop standardized interconnection contracts to improve transparency and clarity for prospective DG customers throughout the interconnection process. Prior to the adoption of a standardized interconnection procedure, most interconnection requests would be forced to work through their service provider, a process that may engender confusion if the utility does not have transparent standards for technical requirements or permitting timeline. The Minnesota PUC updated interconnection standards in 2018 following an 18-month process involving a multitude of stakeholders, improving distributed energy markets further.[22] The standards, closely modelled off FERC's updated SGIP, raised the system capacity limit to 20 MW, provided for fast-track technical screening for smaller systems, and improved the communications procedures between the utility and customer.[23]

Minnesota became a forerunner with perhaps the most significant of the omnibus bill's provisions, in which the legislation directed the Department of Commerce to develop a methodology for compensating distributed generation: the Value of Solar Tariff, or VOST. Most states had established a cumulative capacity limit on the amount of net metered systems utilities

[22] Minnesota Public Utilities Commission, Order Establishing Updated Interconnection Process and Standard Agreement. Docket No. E-999/CI-01-1023 & E-999/CI-16-521, 13 August 2018.
[23] FERC Order 792, Docket RM13-2-000. 22 November 2013: https://www.ferc.gov/sites/default/files/2020-04/E-1_74.pdf

would have to provide retail compensation, usually as a percentage of peak demand, such as Minnesota's aggregate capacity limit of 4% of retail sales. While other states examined raising the net metering program cap, Minnesota including a trigger mechanism to investigate a potential reformulation of DG compensation, which ultimately resulted in the VOST provision in HF 7729 (Doris et al. 2009). The VOST is intended to design economic incentives to remove barriers on the deployment of on-site generation and would serve as an alternative to net metering for compensating DGs. Unlike net metering, DG customers, including CSG participants, are not credited at the retail rate, which includes the utility's fixed cost and volumetric energy charges. The VOST incorporates a range of benefit categories gained from grid-tied distributed solar and is calculated by quantifying the value of "energy and its delivery; generation capacity; transmission capacity; transmission and distribution line losses; and environmental value," which can include reduced carbon dioxide emissions (Minnesota Department of Commerce, 2014). Each value component is figured by calculating the avoided cost of deferred investments or operation to the utility, which theoretically creates more efficient price signals to align the objective of increased DG with the principle of cost causation. The PUC approved the VOST in 2014 but did not make its implementation compulsory.[24] No utility has yet adopted the VOST as a replacement to net metering, but refinements to the valuation structure are presently under development.

The Minnesota case of policy developments highlight the successful navigation of tenuous political terrain. While stakeholders were occasionally placed at odds over the details of implementation over the CSG program, the presence of an amenable utility actor with substantial market power – Xcel – enabled the legislature to pursue innovative policy tools. The

[24] Minnesota Public Utilities Commission, Order Approving Distributed Solar Value Methodology. Docket No. E-999/M-14-65, 1 April 2014.

development of the VOST methodology and interconnection standards was collaborative, multilateral, and instrumental for identifying the benefits of distributed energy to the grid and customer base. States with detailed information revealing DG's benefits as well as supportive coalitions pushed the state to reexamine and improve their regulatory regime.

Nevada: Net Metering Development, Rollback, and Reinstatement

In contrast, the DG policy experience in Nevada was subject to a greater political contentiousness and regulatory vacillations. Following a series of policy adoptions moving Nevada toward renewable energy, the regulatory regime experienced a period of retrenchment and protracted battles over its net metering policy. This section describes the trajectory of DG policy in the state.

Nevada enacted its net metering law in 1997 and regularly updated the policy in the legislative sessions thereafter, generally making incremental refinements to manage the pace of DG integration while expanding opportunities for ratepayers.[25] The Nevada PUC finalized rules for defining eligible net metering systems established the market for renewable electricity credits (RECs) in 2002, and in a separate later proceeding, the PUC allowed utilities to use RECs from net metered system to partially achieve compliance with the state RPS.[26][27] Shortly after the initial regulation, the Nevada legislature moved to modestly increase the system size capacity limit from 10 to 30 kW and expanded financial resources for prospective DG customers.[28] In 2005, the state expanded some aspects of net metering while limiting others. The legislature

[25] Database of State Incentives for Renewables and Efficiency, Nevada: Net Metering Program Overview. https://programs.dsireusa.org/system/program/detail/372
[26] Nevada Public Utilities Commission, Docket No. 02-0529
[27] Nevada Public Utilities Commission, Docket No. 05-7050
[28] Nevada Assembly Bill No. 429, 2003.

imposed an aggregate capacity limit of 1% of the utility's peak demand; the utility would no longer be required to compensate DG customers at the retail rate once DG penetration crossed the 1% threshold.[29] In the same bill, the system size cap was raised to 150 kW, and net metering customers were allowed to carry net metering credits into subsequent months. 2007 saw a more impressive slate of changes: the legislature increased the system size cap from 150 kW to 1 MW, standby charges were prohibited for systems under 100 kW, the PUC was directed to develop a standardized net metering contract, and the legislation allowed third-party ownership of renewable energy systems, whereas previous net metering agreements could be made solely through the utility.[30]

Nevada's political climate would begin to tilt against expansion of net metering in the mid-2010s through partisan activity and utility engagement with the PUC, and signs that the state might consider scaling back net metering requirements emerged through PUC investigations on the economic impacts of DG integration.[31] The PUC had launched an investigation on net metering issues in the state in 2008, which included policy recommendations from PUC staff, the state's major IOUs, and renewable energy industry representatives.[32] Opinions differed on whether a cost-benefit analysis to the state's net metering program was necessary; PUC staff suggested a cost-benefit study was necessary only if the state raised the 1% program cap, renewable developers recommended a study conducted by a third party, and utilities expressed the desire to conduct a study prior to any net metering program expansion. The PUC rejected the report on grounds that studies had been carried out in other states and determined that no new

[29] Nevada Assembly Bill No. 236, 2005.
[30] Nevada Assembly Bill No. 178, 2007.
[31] Republican Governor Brian Sandoval issued an executive order in his first day in office that froze the promulgation of administrative regulations, signaling the political forces pushing the state towards a pro-business regulatory environment (Whaley 2011).
[32] Nevada Public Utilities Commission, Docket No. 08-03022.

analyses needed to be undertaken at the time. The PUC reversed in 2010, ordering an investigation of DG's effects on the economy, environment, electricity rates.[33] The report, which the PUC accepted, found no immediate threat to system reliability from DGs, but with increasing penetration levels, the magnitude of cross-subsidization from non-DG ratepayers to DG owners would increase. Intriguingly, the PUC did not order a direct study of ratepayer impacts in the proceeding; the consultant hired by NV Energy had taken it upon themselves to examine net metering cross-subsidies.[34] The legislature continued to make incremental expansions to net metering following the study's approval; the cumulative capacity limit was raised to 2% of utility peak demand in 2011 and raised again to 3% in the 2013 legislative session.[35] However, in the 2013 bill, the legislature also directed the PUC to open an investigatory docket to study the costs and benefits attributable to net metering in the state, reopening the door for utilities to express concerns over ratepayer inequities before regulators.[36]

Concomitant with the implementation of the PUC's cost-benefit study, the Nevada legislature had shifted from majority Democratic to majority Republican control. The assembly adopted two net metering provisions in 2015 worrisome for renewable energy advocates.[37] First, the state revised the aggregate capacity limit from the 3% peak to a hard-defined limit of 235 MW, which both NV Energy and Sierra Power Company reached merely months after the bill's passage, forcing them to request PUC approval to expand program capacity.[38] Second, the state allowed utilities to impose fixed charges on net metering participants to avoid cost-shifting and

[33] Nevada Public Utilities Commission, Docket No. 10-04008.
[34] Ibid, p.8
[35] Nevada Senate Bill 59, 2011.
[36] Nevada Assembly Bill 428, 2013.
[37] Nevada Senate Bill 374, 2015.
[38] Nevada Public Utilities Commission, Docket Nos. 15-07041 and 15-07041. In a separate proceeding (Docket 05-07021), renewable energy interests petitioned the PUC for an increase in program capacity, but they denied the petition, holding that only the legislature has jurisdiction to increase the aggregate cap.

gave PUC authorization to approve them. Once NV Energy and Sierra Power Company completed the cost-of-service studies mandated by AB 428, the PUC promulgated regulations that significantly depressed the incentive structure for DGs.[39] Retail rates would be reduced to wholesale rates over a four-year period, and transmission and distribution grid charges were trebled for DG customers, netting an approximate 75% decrease in net excess generation compensation. The rate schedule reduction was eventually expanded to allow the grandfathering of present net metering participants to 20 years, but high fixed charges cooled the DG market considerably (Pyper 2017).[40] It should be noted that, while retail rate compensation was dismantled by SB 374 and the associated PUC order, the legislature and PUC did encourage utilities to explore DG options. The bill required utilities to consider DG in planning scenarios, and the PUC had ordered NV Energy to consider distribution system projects and the potential benefits for deploying 100 MW of distributed technologies.[41] Evidently, the PUC did not oppose DG integration altogether, only the violation of equity and cost causation principles from retail rate compensation.

Backlash from the net metering rollback among the solar industry and renewable energy advocates turned the political tides back toward DG's favor. The legislature passed AB 405 in 2017, comprehensively addressing net metering issues while simultaneously laying out a framework for advancing DG compensation beyond retail net metering in the future. The bill mostly restored the compensation structure for DGs, setting the initial price at 95% the retail rate with a gradual step-down through 2035.[42] The bill also repealed the aggregate capacity limit, but

[39] Nevada Public Utilities Commission, Docket No. 15-07041
[40] Nevada Public Utilities Commission, Docket No. 16-07028
[41] Nevada Public Utilities Commission, Docket No. 16-07001
[42] Database for State Incentives for Renewables and Efficiency. Nevada: Net Metering Program Overview. https://programs.dsireusa.org/system/program/detail/372

stipulated that a rate decrease would be triggered once new DG additions reach a cumulative 80 MW in each IOU service territory. In addition, battery storage systems were made eligible to participate in net metering, and utilities were required to file optional time-varying rates for its customers. The restoration of net metering marked the beginning of a series of policy initiatives to boost deployment of DGs in Nevada.

Of the several initiatives advanced to accelerate DG integration following the partial reinstatement of retail rate net metering, including requirements that utilities study the potential for battery storage and include integrated distribution plans as part of their regular PUC filings.[43] Legislators were enabled to pursue more aggressive measures to advance DG deployment with the election of Democratic Governor Steve Sisolak in 2019, when a law passed requiring the PUC to study alternative rate mechanisms whilst eliminating the requirement for the PUC to study and report on the financial impacts of net metering.[44] The legislature also directed utilities to expand options for utility-scale and community solar.[45]

Despite the back-and-forth over distributed solar compensation rates, it is worth mentioning that the PUC gradually adopted environmental regulations to govern utility resource planning. So, while Nevada's critical juncture of retail net metering's rollback and partial reinstatement marks a disruptive period for the renewable energy industry, the PUC still looked to incorporate objectives of environmental protection in structuring utility behavior. Because of this, we might conclude that variation in institutional choice regarding DG access does not occur along a bipolar dimension of pro-environment versus pro-business. Rather, the flashpoint of net metering around the issue of intraclass cost-shifting pushed the regulatory entity toward a

[43] Nevada Senate Bills 145 and 146, 2017.
[44] Nevada Senate Bill 350, 2019.
[45] Nevada Assembly Bill 465, 2019.

position of, arguably to an excessive degree, managing utility and ratepayer risk at the expense of promoting DG development, while at the same time approving utility-proposed DG programs of modest impact. I propose that, in light of the Nevada experience, DG regulations vary to some degree independently of political attitudes surrounding environmental protection. Instead, path dependence deriving from technological lock-in and utility-driven regulatory drift structures institutional decision making around the integration of distributed energy. The next chapter fleshes these concepts out more thoroughly and describes how we might understand the variation in state DG regimes as a function of contrasting state political and economic dynamics, as exemplified in such comparisons as the discussion on policy change in Nevada and Minnesota.

Conclusion

In this chapter, I have worked to demystify the relationship between the economics of infrastructure development and the regulatory construct of a guaranteed rate-of-return for public utilities, and how this relationship led to a natural monopolization of the electricity industry inherently opposed to competition. Utilities balk at competition from independent providers generating renewable-sourced electricity on the distribution system not only because utilities would lose out electricity sales to those providers in the short term, but also because the perpetuity of the cost-of-service utility business model depends upon monopoly control of the electricity market.

Electricity rates are structured so that ratepayers contribute to the recovery of capital costs, but if ratepayers can generate and consume electricity purely on the distribution grid from non-utility-owned assets, the pathway for cost recovery and increasing economic returns form infrastructure investment faces substantial financial risk. The composition of a state's power sector in terms of class of ownership and market access rules influences governance of the energy system, because policymaking institutions tend to assume a position of risk management over policies that would accelerate industrial disruption. Moreover, conventional rate-of-return utility regulation results in unintended consequences under DG integration policies, creating inefficient price signals and raising equity concerns. Empirical research is needed to understand the pull that economic realities such as capital costs and cross-subsidies exert on public institutions, and how those realities interact with political factors to constrain decision making, potentially inhibiting the development of innovative technologies that would promise a range of environmental and social benefits if adopted on a systemwide scale.

Disentangling the causes of variation across states' disposition toward DG integration policy is problematic due to the complicated nature of electricity regulation. This dissertation seeks to contribute to solving this problem by mapping out the political and economic relationships that bear upon policy decisions related to DG integration across US states. What factors pulled Nevada and Minnesota cases in different trajectories? Can path dependence explain reticence toward distributed energy? Which components of path dependence - technological inertia embedded in central power plant investments sustained, and increasing economic returns, cost-shifting - can help us understand the different approaches and pace of DG integration policy? Does increased net metering penetration create existential threat, real or perceived? Or alternatively, is variation explainable as a function of partisan composition of the institutions? This dissertation expands the subject of this question to understand state-level policy change in the aggregate. In order to construct an appropriate frame of empirical analysis, the project must first identify the theoretical bases for understanding the primary influences of regulatory policy change, and this task will be carried out in Chapter 2.

Chapter II

Path Dependence and Regulatory Drift in the Electric Power Sector

Introduction

Public policy research often characterizes the gap between environmental regulations and their intended outcome as a mismatch between means and ends. Policies to regulate the environment, codified by decisions at a prior point in time, establish objectives of environmental protection by structuring and restricting certain economic activities. Regulatory agencies are tasked with carrying out environmental policies to achieve the objectives outlined in statute, but the implementation tools as their disposal are constrained by the earlier-adopted policy framework, which may prove to have limited effectiveness over time. This is because, while public policies are typically stable and difficult to modify, environmental conditions and economic activities evolve, potentially introducing new *social and environmental risks* and the need for new regulations. Regulators cannot supersede their authority by imposing rules beyond the established policy framework, inhibiting the implementation of policy goals if the policy design is inflexible to changing social circumstances. Policies must be actively and frequently updated to align policy tools with changing environmental and economic conditions or achievement of the objectives set in standards of environmental protection will fall short, because static policies cannot adequately assess and mitigate *risks* unaccounted for in established regulatory regimes. A multitude of political and economic factors culminate into two key interrelated phenomena descriptive of the political process surrounding environmental risks: (1) policies and institutions are *not* frequently updated because it is costly for actors to amend them, and (2) the objective of regulation – social or environmental risk – evolves due to changing circumstances, leaving the current regulatory regime with inadequate tools to comprehensively monitor or mitigate risk. The first phenomenon is called *path dependence* while the second is known as *policy or regulatory drift*, and both are characteristic of many domains in US environmental policy (Eisner 2017, Press 2015, Riccucci 2018).

The discrepancy between policy means and ends is evident in regulation of the power sector, which is heavily characterized by path dependence and policy drift (Isser 2015; Ozymy and Jarrell 2012). The natural monopolization, informational asymmetries, and network effects derived from the development and operation of utility infrastructure results in institutional and technological "lock-in," presenting significant barriers to modifying the electricity system to one that is low-carbon and undergirded by decentralized assets. The political-economic path dependence of utility regulation produces an inflexible regime incapable of adequately responding to evolving external conditions such as climate change. The multiplicity of climate risks poses an enormous social challenge for the electricity system, but the aversion of financial risk induces actors away from decisions that would threaten prevailing utility business models and carbon-based technologies. Political-economic arrangements are thus characterized by stickiness and resistance, leaving institutions unresponsive to emergent climate risks such as threats to power system resilience, reliability, and energy security. This project posits that the variation of political-economic factors at the state level coincides with different institutional traits that will could be facilitative of pro-clean energy policy outcomes. Some institutional structures and political-economic contexts will be more conducive to breaking utility path dependencies than others. The states with less favorable conditions for clean energy policy adoption will be more likely to follow a path of policy drift. Hence, we are interested in analyzing the different institutional traits that result in divergent policy outcomes.

In light of path dependence constraining the choices affecting the energy system, I posit that addressing climate risks in the power sector would require a reorganization or reorientation of the incentive structure created by the utility business model to appropriately value the benefits of climate adaptation and mitigation measures, including energy efficiency, grid modernization, and the subject of this dissertation: integration of distributed generation technologies. If risks emerge outside the purview of the established regulatory framework, and alternative technologies could effectively bolster risk management, political and economic actors embedded in the prevailing technological-social system may resist efforts to change the system as they stand to lose out to new sets of actors and technologies under successive incentive structures. This path-dependent nature of regulation creates *policy drift* in states locked-in to fossil fuel-based and centralized utility infrastructure.

The *drift* concept implies incremental policy change, but drift more specifically refers to the gap created when regulatory frameworks become outdated in light of the evolving risk environment. Incremental changes are inadequate for reorganizing regulatory regimes around emergent risks. The need for clean energy technologies and emissions reductions policies to minimize reliability and public health risks has grown, but regulatory frameworks governing the electricity sector in some jurisdictions have been slow to adapt to climate risks and promote greater clean energy technology deployment. This project holds that path dependence and policy drift are not constant across all states, with some states' political and economic environments more conducive to systemic regulatory change than others. As such, the dissertation is focused on the following research question: what can explain the variance in path dependence and regulatory drift across states' regulatory regimes, specifically in DG integration policy?

The following chapter discusses the theories of regulatory change to elaborate on the above explanation of institutional resistance toward DG integration. Outlining the theory will allow us to identify the causal factors of a pro-DG disposition and understand the pattern of DG policy adoption across states. I hypothesize that the variation in DG integration policy can be explained by two theoretical concepts: (1) path dependence, in which the set of policy decisions is structured by prior institutional choices and reinforced by increasing returns, reflected in a state's proportion of centralized generation and market concentration, and (2) regulatory or policy drift, in which industries and regulatory agencies incrementally change the implementation of policies over time, resulting in program outcomes that are incongruous or insufficient relative to policy objectives. First, I provide a brief overview of climate-related risks and situate the project in the policy change literature, justifying the institutional-economic angle for studying power sector regulation against potentially competing theoretical perspectives. Second, the chapter explains the concepts of path dependence and policy drift as tools for understanding regulatory change in the power sector in greater detail. Third, the chapter discusses perspectives on state-level environmental politics to contextualize path dependence and policy change within the US federal system. Lastly, the chapter lays out the method for operationalizing theories of regulatory change to empirically verify whether path dependence and regulatory drift characterize the politics of DG integration in practice.

Theorizing Electricity Sector Policy Change within States

Theories of regulatory change can help us identify the causes of institutional inertia and resistance toward comprehensive modifications of established policy frameworks that would create new regulatory regimes. Generally, comprehensive regulatory change involves the introduction of new policy objectives and sets of political actors, driving the established subsystem participants to maintain their stranglehold on the institution by locking out new participants and incrementally refining existing policies to meet the new policy objective without dissolving the incentive structure that has supported the regulated industry. Interest coalitions stand to lose if outside actors are granted entrance to market resources through the establishment of new policy directions.

The general dynamics above are evident when considering the political conflicts arising from climate and clean energy policy. To briefly summarize the relevance of path dependence and regulatory drift in power sector decarbonization: despite the promise of business model reform to meet environmental objectives and promote innovative technologies, there are strong incentives to maintain the traditional institutional framework that protects the dominant technological foundation of the energy system. Regulated interests would prefer to avert the potential risks of transitioning from the paradigm of centralized utility operation toward an increasingly distributed and renewable power supply. More risk-averse utility companies would seek to use policy venues as instruments to protect revenue and fixed assets from losing out to competitive providers and distributed customer-generators. Public and private actors may assume a position of retrenchment if their market power is under threat from policies promoting DG and renewable energy. However, considering the success of several ongoing state initiatives to reimagine the utility business model to expand the DG market, the problem of institutional inertia is not intractable; a strategy for DG integration that is sensitive to the financial risks and political environment may enable policymakers to address the stickier issues creating friction with policy enabling significant DG access. Identification of the right circumstances for DG policy adoption is useful for both policy analysts seeking to optimally direct their efforts to which strategies are most effective, and social scientists, who seek to understand how wider political and economic patterns shape institutional decision making.

Despite the path-dependent development of political and economic arrangements, there are opportunities for actors to effectuate change incrementally, and even paradigmatic transformations can occur over time. Theories of gradual change, particularly path dependence and drift, are the chosen analytical frameworks for this dissertation, because clean energy and decarbonization policies have progressed in some jurisdictions while others have not, illuminating simultaneously the stickiness of institutions and the ability of actors to gain leverage in molding the trajectory of policy toward different ends within relative stable institutional constraints. Our theoretical bases hold that policy change nearly always proceeds incrementally, but regulatory regimes can be reorganized around new policy objectives given the right conditions. By contrast, other theoretical perspectives emphasize the insularity of entrenched political coalitions in militating against change, or the need for major focusing events to shock the regime into restructuring around new priorities. This project holds the economic, political, and technological contexts to be more important than interest group activity or exogenous shocks when explaining the forces of policy stability and change, making the concepts of path dependence and drift optimal tools for studying change in power sector regulation. Much of the path dependence and drift literature, summarized in this chapter, examine the lock-in effects and regulatory lag associated with technological paradigms, but none have closely studied these concepts as they relate to risk aversion in distributed generation policy.

Studying State-Level Path Dependence and Drift

While there is a great body of literature on policy drift examining social and environmental regulatory regimes at the federal level, and economic change in the electricity sector is understood as being path-dependent, less research has been done to examine drift and path dependence within state-level institutions and policies (David and Bunn 1989, Isser 2015). Following the previous chapter's overview of the evolution of electricity regulation since the Public Utilities Holding Company Act of 1935, state-level institutions structure the most immediate constraints on utility companies through their public utility commissions' (PUC) regulatory charge to govern retail electricity markets. In the contemporary era of federal energy and environmental policy gridlock, state governments are the prime movers of policy change affecting the utility sector in the US.[46] The Energy Policy Act of 2005 was the most recent federal legislative action to encourage distributed generation technologies for the promotion of US energy independence, and no comprehensive legislation has been enacted since. The EPACT05 served to accelerate the expansion of DG integration policies across states, but many of those policies were not regularly updated or adjusted to match the changing conditions of the utility system. In the absence of a national framework creating explicit incentives to accelerate DG integration, we are faced with the restated research question: what factors drive states to adopt DG policies, and what factors prevent states from doing so? The path dependence model, because it emphasizes the importance of timing of decisions and prevalence of technologies, can guide researchers in their selection of the variables most likely to bear on significant economic policy decisions.

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[46] FERC structures utility behavior to some extent through the exercise of its authority over wholesale markets and interstate commerce, but when examining issues related to the utility distribution network, such as on-site generation, state regulatory commissions are the chief policy venues in which consequential choices affecting economic returns and grid access are handed down. See Chapter One for further discussion.

This dissertation seeks to ascertain whether certain sets of economic and political factors improve a state's chances for establishing a framework toward building a robust regulatory regime that supports DG integration. I propose that political resistance toward DG integration can be causally explained as a function of some combination of political environment, economic factors, and power system characteristics that together determine the cost risk of adopting DG integration policies. Alternatively, certain political and economic conditions may lead state institutions and private actors to accept a greater level of risk as an acceptable measure to further the state's policy objective of reduced reliance on fossil fuels through increasing DG adoption. Part of the answer to the above questions depends upon the structure and composition of a state's utility market. Because electric corporations are the arm of policy implementation of the power sector, some utilities act as the *de facto* policy authority in regulating the interconnection of renewable energy to their networks in states with less stringent PUC oversight. Depending on the state's political environment and economic conditions, state legislation supporting DG may eventually prove ineffectual or vulnerable to political contestation, leading to regulatory drift. On the other hand, a favorable alignment of political and economic factors combined with a utility's propensity for DG programs may allow for a DG program's success. The next section provides an illustrative example of the risks posed by climate change and the regulatory insufficiencies created by policy drift to guide understanding of theories of gradual policy change and institutional inertia.

Illustrating Policy Drift and Climate Risk: Texas Winter Outages

While climate risks may be considered as having abstract or diffuse effects, certain recent events cast the political-economic ramifications of neglecting climate risk in sharp relief. Climate scientists predict that the polar vortex phenomenon, in which the polar jet stream becomes unstable and allows arctic air to dip into temperate and subtropical latitudes, is exacerbated by climate change (Beradardi 2021).[47] In February 2021, the polar vortex caused the Texas power grid to experience a series of cascading events: extreme cold tripped roughly 34,000 megawatts (MW) of generation capacity offline and created a massive spike in energy demand, resulting in severe shortages in electricity supply (ERCOT 2021). Because the Texas power grid is operated independently from the eastern and western US grids, the market could not correct for energy supply shortages by importing electricity from neighboring states. Additionally, the grid operator – the Electric Reliability Council of Texas (ERCOT) – relies on scarcity pricing to facilitate energy transactions on a highly competitive market, leading to astronomical electricity prices during the outages, causing some retail suppliers and cooperatives to declare bankruptcy and the forced resignations of utility commissioners and ERCOT board members (McWilliams 2021). The events have ignited political debates on the scope of authority of the PUC versus the grid operator and the appropriate financial mitigation measures, with potential reforms to the Texas grid under discussion by state legislators (Mekelburg 2021). Energy experts tend to attribute the grid failures to a multitude of factors, but ultimately, the crisis was driven by inadequate infrastructure planning and a regulatory environment that has incentivized competition among retailers to foster affordability.

[47] Science and Climate Definitions: "What is the polar vortex?" *University of California Davis, Science and Climate.* Retrieved from: https://climatechange.ucdavis.edu/climate-change-definitions/what-is-the-polar-vortex/#:~:text=How%20Is%20the%20Polar%20Vortex%20Affected%20by%20Climate%20Change%3F&text=The%20change%20is%20warming%20higher,bringing%20polar%20air%20farther%20south.

The myopic focus on competition has meant that certain risks are not factored into the utility regulatory model and long-term resource planning. While financial risk to utilities and ratepayers has served the state policy goals of keeping prices low, other risks such as reliability, security, and resilience have not been prioritized in the regulatory model nor priced into the rate calculation. Because extreme cold has not historically befallen the Texas system, utilities have not proactively pursued measures such as *weatherization* for generation assets and natural gas pipelines to protect energy flows against disruptive weather events, because the cost of adopting comprehensive weatherization programs would negatively impact utility profitability in the short-term. Long-term considerations, such as the need to protect infrastructure against evolving weather patterns driven by climate change, are not factored into the price structure, hence utilities have repeatedly punted on system improvements. To this point, energy and policy analysts point out that similar, less severe conditions swept the ERCOT system in 2011, yet regulators and utilities allowed the grid to continue aging under business-as-usual operations following the disruptions (Galbraith 2011, Irfan 2021). ERCOT declined to adopt mandatory reliability standards, instead suggesting mere voluntary measures to protect facilities (FERC and NERC 2011). In a point that will be significant for the discussion of alternative explanations to policy drift, exogenous shocks were initially insufficient to reform electricity market governance.

Not only did the system prove to be lacking in resilience as it took several days to restore power to the inflexible and fragmented system, but the system was also severely lacking in reliability. The weather events exposed major risk vulnerabilities, but due to the stagnant and permissive regulatory framework within ERCOT, the regime has not adapted to address climate risks as illustrated by the polar vortex. Despite the occurrence of similar events a decade earlier, ambiguity and disagreement over jurisdictional authority between the PUC and ERCOT persisted, and neither have sought to mandate the inclusion of technological updates to improve resilience and reliability due to their incentive to avoid foisting associated short-term cost risks on utility companies. As infrastructure is exposed to new risks, ERCOT's regulatory framework has remained stagnant due to path dependence, and this is the essence of *policy drift*. If we consider regulatory regimes as *risk protection regimes*, the analytical framework of policy drift provides exploring the discrepancy between a policy's means and ends in terms of the mismatch between what risks are being carefully regulated and the risks that are left unaddressed. If the objective of electricity regulation is to protect ratepayers and utilities against risk, the Texas system failed as the regime "drifted" from risks emergent out of changing environmental circumstances, created vast underinvestment in electricity infrastructure.

The Texas case is not presented to argue that higher amounts of distributed generation technologies would have averted the energy crisis. Rather, this example illustrates the discrepancy between the stated purpose of policy – risk protection – and the regulatory tools allowed under the prevailing regime to achieve the objective. Fulfilling the policy objective of climate risk mitigation requires responsiveness to a multiplicity of social and environmental risks, but the conventional utility business model inhibits responsiveness. The regulatory compact *overvalues* volumetric sales and central infrastructure and *undervalues* resilience measures, energy conservation, and decarbonization, all of which may be excluded from pricing structures in states wary of their effects on costs to ratepayers and utilities. However, states can pursue a diversity of policy initiatives to promote the development of a portfolio of technological upgrades to simultaneously increase resilience and decrease greenhouse gas emissions from power infrastructure. Weatherization measures, improved resource planning processes, and distributed energy integration programs would all enhance the objectives of resilience and environmental protection, substantially alleviating environmental risks in the short-term and accruing financial benefits in the long run. This project specifically examines DG integration due to its implications for the utility business model, but other research could examine any one of these policy types to identify the causes and measure the variance of regulatory drift in state-level utility regulation. Next, we must lay the theoretical groundwork for explaining path dependence and drift.

Defining Path Dependence: Transaction Costs and Increasing Returns

Theorizing on the causes of regulatory drift and path dependence requires an understanding of the causes of policy change more broadly. To that goal, this section defines path dependence before offering a cursory review of two interrelated bodies of theory: (1) literature elucidating the mechanisms of institutional change, particularly path dependence, and (2) the analytical framework of regulatory regimes and policy subsystems. Then, I delve into a more detailed discussion on how gradual forms of change and the components of institutional path dependence can be understood in the context of energy policy as manifested in technological or carbon lock-in.

An Overview of Transaction Cost Theory

Path dependence, while having ubiquitous employment in social science, is a multi-dimensional concept, and operationalization for empirical study requires precise definition. In political science, economics, and other social sciences, path dependence has often been construed in a broad sense: that political actions shape the trajectory of future political actions or constrain the universe of public choice based on prior institutional decisions (Pierson 2000, Eisner 2017). The conceptually broad definition of path dependency generally reflects the belief that the historical development of institutions matters in terms of explaining policy change over time. The *temporality* of political choices is key for determining the possible universe of future actions and the probability of a particular set of outcomes (Pierson 2000, David and Bunn 1989). In other words, policy change cannot be understood without explicit connection to the political and economic context. Political economic conditions are bound in moments of time, placing great import on the cumulative sequence of policy choices. Determining the set of possibilities in a given policy area can be understood as a probability function of both the social context and the previously established policy regime. Hence, the concept of path dependence not only helps explain the historical trajectory of a regulatory domain, but also the resistance to institutional change from external and internal actors.

While the broad conception of path dependence can elucidate the centrality of institutional development in determining policy change, the notion that institutions and established rules matter seems self-evident yet lacks a positive empirical focal point. For a clearer operational conception, we can begin describing path dependency as a mechanism driving economic progress that is produced by technologies, institutions, and the symbioses between them. There are a variety of theoretical approaches in political economy to explain why a public policy choice at one point in time narrows the likely range of policy options in successive windows of opportunity, and this project follows the perspective of Douglass North's theory of institutional change. He proposes that the interconnection between formal institutional constraints, available technologies, and subjective perceptions of the public would almost always result in incremental economic change. Instantaneous transformative political change is thwarted by the embeddedness of institutions in prevailing economic forms, buttressed by slow-moving social conventions, in which industrial organizations with superior agenda-setting power tie institutional venues to the well-being of those economic forms through electoral incentives and informational asymmetries. I elaborate on North's argument below.

The key to understanding the incremental nature of policy change, and why institutional frameworks often perpetuate inefficient economic models and block potentially more efficient public choices, is *transaction costs*. North argued that problems of efficient public policy can essentially be described as problems of human coordination and cooperation, and successful coordination that leads to socially efficient outcomes is often impeded by the transaction costs inherent in exchange (North 1990a). The transaction cost theory is useful for explicating the limitations of neoclassical economic theory in devising a complete formula of the determinants of economic productivity, which holds that resource inputs such as fuel prices primarily determine the total cost of production. If total costs were purely derivative of resource costs, prices would serve as an efficient mechanism to allocate goods and wealth. However, this model is incomplete because several assumptions would have to be satisfied in order for resource inputs to comprise total cost: commodities and their attributes would have to be identical, market exchange could not be temporally or spatially dispersed, and all actors would have complete information about the valued attributes of the commodity (North 1990a: 30). Markets are not ideal in practice, because commodity units diverge in their attributes, exchange between parties can occur at distance in space or time, and consumers cannot possibly have the same information of a commodity's attributes as producers. These imperfections give rise to two categories of transaction costs that must be factored into total costs: (1) the costs of *measuring* the value of a commodity's attributes, and (2) the costs of *enforcing* the rules of exchange, including property rights of the producer and monitoring for regulatory compliance. Both categories involve the cost to acquire accurate information, and a theory of exchange that incorporates the costs of information acquisition for valuation and enforcement comports closer to reality than a model that assumes perfect symmetry of information and no cost to procure it.

Because measurement and enforcement information requirements are costly, interested actors are compelled to devote resources to lower transaction costs to facilitate as frictionless an exchange as possible. Coordinated interaction in an advanced economy is especially difficult due to the prohibitive costs of collecting information and enforcing property/contractual rights associated with high levels of industrial diversification and specialization (North 1990a). Hence, in periods of rapid industrial expansion, the bureaucratic apparatus would concomitantly expand to increase the capacity of state intervention to correct for inefficiencies arising from unregulated firm activities (Polyani 1944). The role of institutions in this perspective is to lower the costs of transacting by reducing the *uncertainty* in behavior among parties; unequal access to information and lack of clear rule procedures would mean that markets will behave unpredictably in the individual and aggregate levels due to absence of structures designed to reduce uncertainty. That lowering transaction costs is the central objective of state institutions is similarly found in the public policy literature on market failures. Policy analysts justify government interventions into market activity based on informational asymmetries, natural monopolies, and negative externalities (Weimer and Vining 2011). Each type of market correction can be defined as reducing transaction costs; correction of informational asymmetries and natural monopolies lowers both the costs of measurement and enforcement among the market's principals and agents. Addressing negative externalities solves the inadequacy of measuring the value of a commodity's production in cases that a good's price does not incorporate its deleterious attributes.

Transaction costs not only apply to economic markets but also the "political markets" of electoral systems and selection process of public policy alternatives (North 1990a). Informational asymmetries shape politics by their effect on principal-agent relationships; the principal often is limited in their access to information relative to the agent (Miller 2005). Citizens do not have access to the same information as elected officials, elected officials do not have the same quality of information as regulatory agencies, and agencies might have less complete information than their stakeholders. In each case, actors devote resources to create institutions in order to *lower transaction costs* of *measuring* the valued attributes of an agent and *enforcing* the preferences of the principal. Media lowers the cost for interest groups to provide information on candidates to the public by providing an outlet to advance policy frames, allowing organizations to highlight the most important policy issues at stake in an election (Stone 1988). Legislative bodies establish constraints that limit agency discretion in policy areas with complex information and uncertain outcomes (Epstein and O'Halloran 1994, Moe 1990). Agencies institutionalize administrative procedures for information gathering and compliance monitoring to reduce uncertainty in the behavior of regulated entities (Mazmanian and Sabatier 1983). By establishing institutional designs that enable principals to measure and enforce the agent's fulfillment of the principal's objectives, the "political market's" transaction costs are thereby lowered.

There is a flip side to the investment of resources in transaction cost-lowering institutions: establishment of constraints and procedures to lower transaction costs will result in risk-averse behavior, because once resources are devoted to promoting a frictionless market, the actors are invested in maintaining the existing framework to avoid uncertainty and protect existing pathways of economic returns. A change in institutional frameworks would entail a change in the opportunity set for actors, raising uncertainty about transaction costs, and by extension, firm profitability. We could conclude that transaction costs perpetuate suboptimal institutions, because changing political-economic circumstances creates uncertainties about the costs of the new economic arrangements, introducing new transaction costs and hence new risks, which demands further resources devoted to lowering them. I argue this aversion to risk is the primary source of path dependence and will be elaborated further in the discussion on increasing returns and regulatory regimes later in the chapter.

Transaction Costs in the Electricity Sector and Distributed Generation

It is not difficult to see how North's conceptualization of transaction costs applies to utility sector regulation, as fewer commodities are characterized by a greater magnitude of market imperfections than the provision of electricity. The development of public utility companies as natural monopolies presents major ramifications for the measurement and valuation of electricity and the enforcement of property rights. The processes of price setting and infrastructure planning are subject to high degrees of uncertainty directly following from electricity's attributes and the service guarantees of utilities, involving unequal access to quality information and high demands on institutions to ensure that the principles of security, reliability, and affordability are satisfied by regulated entities (Fremeth and Holburn 2012, Gormley 1983). PUCs and state legislatures are compelled to develop rigorous administrative requirements to safeguard ratepayers against utility practices that would transgress the standards of equity and reasonableness, but implementation of such mechanisms come at a cost, which might help explain why regulatory commissions resist industrial change that would upend the utility business model.

First, the cost-of-service formulation of utility rates possesses intrinsic challenges to accurately calculate the multitude of factors constituting the total cost of electricity service.

Transaction costs in both the measurement of electricity's attributes and the enforcement of market rules are innumerable. Recall the rate design calculation that allows utilities to recover the costs of capital investment and earn a guaranteed rate-of-return on maintenance and operation expenditures from Chapter One. Utilities must build evidence to set electricity prices in rate cases, and while PUCs have increasingly professionalized with the development of administrative procedures to facilitate accountability, utilities generally have better access to accurate information on the value of their own assets than regulators (Fremeth and Holburn 2012). We might call the resource demand for institutions to provide overseers with accountability mechanisms as bureaucratic decision costs or enactment costs (Stephenson 2007, Fremeth and Holburn 2012). With the high level of administrative investment directed toward facilitating transparent and accountable investment, industrial change such as distributed generation integration places new demands on the institutions for reducing the information costs that arise from greater deployment of DG systems.

Second, utility companies are required to make a variety of assumptions when devising long-term resource plans. In order to justify reasonable infrastructure investments, part of integrated resource planning (IRP) requirements direct utilities to develop multiple forecasting models that reflect the variance in possibilities across a number of scenarios affecting electricity demand. Weather fluctuations and DG penetration variables are typical variables included in IRP forecasting models, which (a) can vary widely, making the location and amount of capital investments subject to great uncertainty, leading to (b) a relatively wide range of probable electricity prices. The upshot is future resource adequacy requirements and planned facilities cannot be precisely determined in regulatory procedures, especially since utilities plan for 15-, 20-, and 30-year time horizons (Girourard 2015).

Returning to the issue of distributed generation policy, it is clear how transaction costs perpetuate less-than-efficient forms of electricity policy via the heightened measurement and enforcement demands presented by increasing levels of DG integration. Regarding measurement, the expansion of DG penetration exerts downward pressure on the *value stream* to utilities due to DG customers' ability to circumvent paying into infrastructure costs under a retail rate net metering program. The cost-shifting issue pressures decision-makers to reexamine the value of electricity generated by systems located on the distribution network to determine whether DGs are compensated for the true cost of electricity production. In the example of Nevada's net metering program in Chapter One, the PUC came to reflect utility concerns about the regressive effects of quantity of cross-subsidies, prompting an investigation into the costs and benefits of distributed solar energy, ultimately resulting in a political battle that punted on the question of value to be wrangled out in future proceedings. On a simpler level, measuring the value of net-metered electricity requires the literal metering of the bidirectional flow of electricity, requiring the installation of "smart meters" to accurately capture the kilowatt hours consumed and produced.

Regarding enforcement, PUCs must uphold the ownership rights of utility corporations, including the guarantee that utilities provide *exclusive* electricity service in their delineated geographic territory. For instance, enforcement of ownership rights compels the establishment of interconnection procedures to ensure that new generation resources do not significantly negatively affect the utility system. In the context of net metering policy, enforcement costs entail the resources devoted to monitoring progress toward the cumulative capacity limit for net metered systems and establishing procedures to determine whether the aggregate limit should be modified once the threshold has been met.

When considering together the measurement and enforcement costs presented by DG integration, it is clear how the connection between institutional frameworks and business models stymies major policy change in the electricity sector. The innovation of transformative technology – distributed generation – challenges the prevailing economic valuation structure, which threatens the ownership rights and value of the good – electricity – that flows from centralized utility assets. Douglass North (1990a) generalizes the dynamics that result from changing ownership structures driven by evolving technologies:

> …the more easily someone can affect the income flow from someone's assets without bearing the full costs of their action, the lower is the value of that asset…. The rights to an asset generating a flow of services are usually easy to assure when the flow can be easily measured, because it is easy to impose a charge commensurate with a level of service. Therefore, when a flow is known and constant, it is easy to assure rights. If the flow varies but is predictable, rights are still easy to assure. When the flow of income from an asset can be affected by the exchange parties, assigning ownership becomes more problematic. When the income stream is variable and not fully predictable, it is costly to determine whether the flow is what it should be in that particular case. In such an instance, both parties will try to capture some part of the contestable income stream. (p.31-32)

The issues highlighted by North the above passage has direct applicability to DG integration. DG customers affect the flow of utility assets by generating their own electricity, which amounts to sales of kilowatt hours *not* made by the utility, resulting in profit losses from central utility power plants. Under retail rate compensation structures for DGs, net metering participants do not bear the full costs of their action, because they do not pay transmission and distribution charges, despite the fact that net metered systems are grid-tied and depend upon utility infrastructure to some extent. Due to the variability and intermittency of generation from solar technologies as a function of weather conditions, the flow of services from DG is not known and constant. The output and value of DG systems are not fully predicable, and measurement of value is hampered by the absence of time-variant and location-variant electricity prices. Dynamic rate designs calibrated with greater temporal and geographic resolution might alleviate the difficulties in the measurement of DG-sourced value of electricity, but most state ratemaking procedures are not equipped to advance such measures of precision. In light of these technical and economic characteristics of DG integration, the assignment of ownership and determination of value for DG-sourced power becomes problematic, and results in political contests over the costs, benefits, and property rights to self-generate as experienced in Nevada.

I conclude this section by summarizing the argument that transaction costs characterize electricity regulation, which provides the political-economic foundation of institutional path dependence. Cost-of-service regulation, because the revenue requirement formula is built on a model of capital investments and volumetric utility sales, is singularly concerned with promoting infrastructure expansion and more energy-intensive operation of power plants. The rate-of-return construct incentivizes the build-out of energy facilities without mandating their efficient functioning for several reasons. The supply-and-demand dynamics of electricity markets is not calibrated to the diurnal or seasonal consumption patterns does not precisely figure into electricity prices, because the rate calculation in rate cases utilizes averages and does not make granular adjustments based on temporal or locational attributes. Because costs are not localized based on the specific geographic characteristics of a facility site, and because costs have not been calibrated to short time intervals that would reflect variance in power system demand across daily fluctuations, the conventional utility business model is locked into a valuation structure with incomplete information on the true value of electricity's attributes. The valuation structure locks out other values from the rate calculation that would otherwise promote greater system efficiency, but instead the regulatory model incentives *inefficiency* because utility profitability is a function of capital investment and retail transactions.

The transaction of electric power itself disincentivizes policy change that would increase system efficiency; hence utility stakeholders might push back on attempts to advance conservation efforts or open the market to non-utility smaller power providers. Alternative modes of regulation, such as incentive mechanisms to award utility performance outcomes beyond security/reliability/affordability objectives, would be a necessary -though possibly insufficient- measure to avert the inefficient consequences of a regulatory compact that guarantees a return from capital investment and electricity sales (Fremeth and Holburn 2012). Under the traditional utility business model, DG integration policy would have the effect of (a) placing new demands on PUCs for the valuation of electricity and generation assets, and (b) creating the need for mechanisms to protect the property rights of utility companies by ensuring sustained rate-of-return amidst increasing proportions of self-generation. Now that I have defined transaction costs and its applicability to electric utility regulation, I can begin to discuss the economic mechanism that perpetuates risk-averse behavior and incremental policy change: increasing returns.

Increasing Returns

Path dependence is descriptive of political processes because governmental policy making generally adheres to a status quo bias, and we cannot explain the present situation without tracing backward through time the chain of causal events that created the conditions necessary for the observed outcome. Path dependence is caused by two factors. Transaction costs, conceptualized as market imperfections, is one aspect of path dependence and explains the basis for the existence of institutions and organizations; they are structures established to facilitate interaction and coordination among actors in a society by lowering transaction costs related to measurement and enforcement of goods and services (North 1990). In regulatory policy, public agencies lower transaction costs though routinized procedures and standards, which has the effect of reducing uncertainty; disruptive technologies such as distributed generation creates the need to invest resources in lowering the associated transaction costs from changes in valuing the attributes of electricity and assigning/enforcing ownership rights with increasing amounts of DG installed on the utility system. The second source of path dependence is *increasing returns.* Existing institutional arrangements contain incentives to protect against critical policy change because the prevalent technology provides increasing returns to political actors and economic interests, whereas the cost of switching to an alternative solution increases markedly over time (Pierson 2000, Arthur 1994). To garner a complete understanding of institutional path dependence and risk aversion, one must carefully examine the relationship between transaction costs, increasing returns, and the institutional constraints associated with prevailing technologies. This section elaborates on the definition of increasing returns and explains the concept's relevance to distributed generation policy.

The increasing returns concept was initially developed by economists as a contrast to marginal returns to explain how market inefficiencies do not automatically self-correct, and the difficulty in changing course increases drastically over time, allowing inefficient choices to persist. Under increasing returns, public choice consists of a strong stochastic element that governs the selection of alternative solutions (North 1990, Pierson 2000). Choice into a particular course of technology may be driven by accidents or a chain of "small" historical events, leading one technology to win out over others at the initial juncture point. A technology, once selected, tends to be locked-in through positive feedback processes, as the institutional framework incentivizes protection and reproduction of the technology due to the relative benefits to political and economic actors associated with maintaining the prevalent technology (Pierson 1993, David and Bunn 1989, Arthur 1994). The choice of technology may be less efficient than a forgone alternative, but since transaction costs obscure the information associated with a good, especially future value, decision-makers have no method of accurately comparing the efficiency across alternatives at the initial choice point. Additionally, because transaction costs require the investment of resources into enforcement structures, decision-makers tend to see greater benefit in maintaining the present arrangements, as altering enforcement structures to match the new technological environment would prove costly, with benefits accruing only in the long-run.

The reality of increasing returns illustrates the path-dependent nature of the economy and the centrality of institutions in structuring interaction and exchange. The stickiness of institutions and status-quo bias is explainable as a result of the increasing returns characteristic of technology markets. In a perfect equilibrium market model, transaction costs would be zero, and institutions naturally adjust to the optimal choice of technology through negative information feedback (North 1990). Market signals alone would be sufficient to drive institutions to adopt the appropriate model of evaluation and enforcement of property rights. In reality however, due to the existence of high transaction costs in advanced technological fields, increasing returns creates a political and economic gravitational center grounded in the existing set of institutional constraints (Arthur 1994, Pierson 2000). The formal constraints, by their function of lowering transaction costs and providing increasing returns, creates the incentive structure that has driven investment of resources into the chosen technology, creating a symbiotic relationship between institutions and economic actors, thus generating path dependence and inhibiting policy change.

Economic markets or governmental institutions can be subject to increasing returns, and this illustrates two components shaping the path-dependent development of markets and institutions: *suboptimal efficiency*, in which certain technologies tend to become dominant in the marketplace despite the fact that an alternative technology might have awarded larger payoffs, and the *temporality of choice*, in which the timing and sequence of selecting among policies will factor significantly into costs. Earlier choices will be less costly and more impactful, whereas choosing alternatives at a later point in time once down a particular course will require more resources to switch with a lower probability of altering the outcome (Arthur 1994, Pierson 2000). Brian Arthur (1988, 1994) postulated four self-reinforcing mechanisms that characterize markets with increasing returns, each acting as a driver of positive feedback. It is evident that all four self-reinforcing mechanisms apply to public utilities.

First, technologies subject to increasing returns involve *high set-up or fixed costs*. If assets are prohibitively expensive, and the deployment of the technology faces geographical constraints, one firm or technology may occupy the field via natural monopoly (Krugman 1991, North 1990). Because initial costs can be spread over the volume of an asset's output, technologies with high fixed costs offer increasing returns as the value of the asset is gradually recovered through market exchanges (Pierson 2000). As discussed in Chapter One, electricity infrastructure involves very high fixed costs. Capital-intensive assets such as electric generation and delivery infrastructure recover the cost of set up over the course of their output through retail electricity sales. Switching to another technology would incur not only the cost of setting up an alternative system, but also the opportunity cost of ending the stream of increasing returns provided by the prevalent technology. DG integration may present an obstacle for fixed cost recovery, since DG owners do not pay for commodities flowing from utility generation assets and may not be paying into grid costs. Economies of scale are particularly powerful at producing lock-in for technologies with high set-up costs (David 1985).

Second, technologies associated with increasing returns involve *learning effects*. Economic organizations and institutions acquire knowledge and skills that improve utilization of the technology over time and innovate in compatible applications. Learning effects lower costs and improve efficiency, but not necessarily to a greater degree than a technology alternative not selected (Arthur 1988, David 1985). This "learning-by-doing" results in an incremental pace of technological progress and has the effect of raising the good's value through future innovations (David and Bunn 1989). Learning as a self-reinforcing mechanism in economics is similar to the concept of policy learning, in which political entrepreneurs adapt policy tools to changing social conditions (Sabatier and Jenkins-Smith 1993). In 2017 for example, public utility commissioners in Colorado approved (1) a major investment of $612 million by the state's largest utility – Xcel Energy – into a program to deploy advanced metering infrastructure or "smart meters," enabling Xcel to implement demand-side management programs and interconnect distributed energy resources, and (2) a pilot *decoupling* rate to remove disincentives for energy conservation (Proctor 2017, T&D World 2016). The decision followed a 2016 rate case in which the PUC granted approval for a smart meter pilot program, which provided valuable information on the costs and benefits of smart meters, particularly regarding reliability, energy conservation, and the technical potential for integrating distributed generation systems.[48] Once uncertainty over the

[48] Colorado Public Utilities Commission. Public Service Company of Colorado - AL 1712 - Tariff No. 8, Docket No. 16AL-0048E. 11 November 2016

technology's impacts was reduced, decision-makers felt prepared to devote resources toward adopting further system improvements.

The next two mechanisms are closely related. Third, technologies with increasing returns are characterized by *coordination effects*, in which the potential value to actors increases as more participants enter the market (Arthur 1994, Pierson 2000). Coordination effects are especially prominent in "network technologies," in which efficient performance can only be achieved by ensuring that the constituent components of a complex system are functionally compatible and integrated (David and Bunn 1989). Additionally, as one technology becomes dominant, the cost of coordination between users drops, resulting in positive network externalities. Coordination effects are strongest when the technology is associated with "linked infrastructure," because increased market penetration encourages investment in the infrastructure that supports the technology (Pierson 2000: 254). David and Bunn (1989) describe products dependent upon linked infrastructure as "gateway technologies," in which a device must facilitate technical connections in order to be utilized "in conjunction within a larger integrated production system" (170). As the utility system based on centralized power provision expanded in the early 20th century, greater numbers of ratepayers experienced the benefits of reliable and affordable electricity, spurning further investments into generation, transmission, and distribution assets. The reliability and affordability benefits associated with utility network expansion create direct network externalities and incentivize the maintenance of the "installed base" of electricity infrastructure: "the 'installed base' comes to weigh more and more heavily in determining choices about interrelated capital investments for supplying and using the network technology" (David and Bunn 1989: 169). Further, DGs might be considered gateway technologies because their efficient performance depends upon technical interconnection standards to assure reliability and safety.

Fourth, increasing returns are driven by *adaptive expectations*. As more users adopt the technology, the expectation that the technology will continue to be supported by consumers and investors grows, and actors adjust their behavior to fulfill the expectation (North 1990; Pierson 2000). Institutional constraints fuel adaptive expectations due to their function of reducing uncertainty. A particular institutional framework that incentivizes the expansion of a certain technology increases the likelihood that users can capture the technology's benefits, causing propagation and further expectations of prevalence. Regarding the electricity sector, ratepayers do not consciously "buy-in" to centralized utility infrastructure based on their expectations that the user network embedded in the utility system will grow, because electric service provision is considered a necessity. Additionally, the choice between utility service and self-generation is not dichotomous, because DG customers are grid-tied and most still rely on the utility system. However, one can consider the role adaptive expectations plays when framing the choice between energy sources. Adaptive expectations have not taken hold for DG technologies such as rooftop solar PV or behind-the-meter battery storage, because these markets, while expanding, are relatively nascent and have not gained appreciable adherence into generation portfolios. Utility assets such as coal and nuclear facilities, on the other hand, are expected to be financed and maintained, expectations of which are fueled by their historical performance and utility investments into infrastructure. Following this line, central utility assets are buttressed by decades of subjectively constructed ratepayer buy-in, while the progress of distributed generation is only beginning to incrementally gain traction in the 21st century, justifying state policy interventions such as net metering programs to accelerate the growth of DG markets up to the point that adaptive expectations self-reproduce the technology.

Now that I have outlined the self-reinforcing components of increasing returns and their applicability to the electricity sector and DG, we must consider the ramifications of using the increasing returns concept as an explanatory tool for describing the sources of stability in institutions and public policymaking. Arthur (1994: 112) described four consequences of increasing returns for economic outcomes, but other scholars such as North (1990) and Pierson (2000: 253) have conceptualized these properties within the political sphere: (1) *multiple equilibria* - choices are indeterministic, unpredictable, and a wide range of outcomes is possible from the outset of a formative juncture; (2) *potential inefficiency* - the technically inferior technology gains market adherence as a result of a sequence of chance events, with imperfect information obscuring comparison of the long-run value across technological options; (3) *lock-in* – a solution is costly to exit from or reverse, and alternatives face difficulty in breaking into the field once a solution dominates the marketplace; and (4) *inertia/path dependence* - positive feedback processes drives institutional and economic activity toward a stable policy equilibrium that is resistant to change.

When we turn to the larger picture in determining how established institutional constraints shapes the relationship between the economy and the public, that path dependence is a stronger force in politics than in economic markets. There are several reasons to believe that *contingency*, in which "small" events can potentially lead to significant consequences, and the *timing and sequencing* of choices, in which early events are more determinative of the ultimate outcome than events later in the sequence, play a larger role in the path dependent development of institutions. Collective action dilemmas such as the free rider problem, the durability of legal structures, power asymmetries in bodies of authority, and the opacity of political processes all contribute to the increasing returns dynamic in institutions (Pierson 1993, 2000). Furthermore, unlike firms, institutions do not necessarily compete, and the absence of a clear mechanism to achieve efficient performance makes alternative forms of governance difficult to evaluate. The nature of political behavior contributes to forces of path dependence because of the tendency to skirt long-term considerations and focus on short-run impacts; if appreciable benefits only accrue in the long-run, the time horizon for decision making will remain limited. Policy problems such as climate change present far reaching-consequences, and solutions such as energy transition initiatives might be initially costly, making the political risk of supporting such efforts a challenging obstacle to fuel-switching systemwide.

Additionally, not only are institutions inherently biased toward the status quo because of risk aversion and transaction costs, but also because actors explicit design institutions to make them difficult to dismantle. Political actors must navigate and engage within an uncertain environment, and in order to heighten the probability of their policy agenda's effectiveness and endurance over time, actors devise bureaucratic structures to constrain future decision-making (Moe 1990). All of these considerations highlight the *bounded rationality* of political actors; decision-makers have inherent cognitive limitations and attempt to make the best choice given the social conditions and agenda goals, but numerous factors contributing to increasing returns binds policy choices to the present course (Simon 1955, Baumgartner et al. 2014). A combination of electoral incentives, procedural complexity, institutional durability, and imperfect information tends to lock-in choices of technology whilst increasing the risk of adopting an alternative. The constellation of political actors and economic organizations that comprise the prevalent regulatory regime in a policy area play an active role in perpetuating lock-in and path dependence, because the incentive structure created by the institutional arrangements diverts actors from making the costly choice of switching to an alternative technology; the relative benefits of maintaining course will almost always exceed the costs, because the resource cost and risk of comprehensive change cannot recover the lost increasing returns when forsaking the technology in question. This theme will be revisited in the next section on regulatory regimes.

Carbon Lock-In

Having defined path dependence as a phenomenon driven by transaction costs and increasing returns, this section concludes the discussion on path dependence as exemplified in the work on carbon lock-in to clarify the influence of increasing returns on the politics of renewable and distributed generation policy. Social scientists focused on climate issues find path dependence a useful concept for explaining why policymakers might be hesitant to adopt comprehensive technological solutions such as supporting the expansion of renewable energy markets and imposing rigorous pollution control regimes (Unruh 2000, Brown 2017, Stein 2017). Governing institutions are tied to the technological system of fossil fuel-based energy infrastructure, because the investment offer increasing returns due to massive economies of scale. By contrast, fuel-switching to renewable energy would pose significant economic cost for embedded firms and institutions at least in the short-run, whereas financial and environmental benefits are realized only over the course of distant time horizons. Increasing returns are provided from expanding usage and innovation upon the "installed base" of the utility system, characterized by market concentration/corporate protections and centralized assets predominantly powered by carbon-emitting sources of energy. In energy policy research, the increasing returns and path dependence deriving from the society's technological base is described as *carbon lock-in* (Unruh 2000, Carley 2010, Seto et al. 2016).

The discussion on increasing returns and transaction cost theory demonstrated that institutions and economic actors are together bound to the development of a particular technological pathway. Formal institutional constraints, such as a regulatory/statutory framework, induces the establishment of public policy that maintains the flow of returns and minimizes uncertainty, hence, prevalent technologies are not easily supplanted, because the technology is embedded in institutional constraints and vice versa. These dynamics are illustrated by Gregory Unruh's (2000) conceptual framework of the *Techno-Institutional Complex* (818). The framework is useful for understanding the interrelated nature of firms, institutions, and how decision-making each is inextricably tied to the social context. The Techno-Institutional Complex, or TIC, is a product of the path-dependent nature of market and institutional development. Both governmental institutions and economic organizations become tied to the installed technological infrastructure through positive feedback processes, and "once locked-in, TIC are difficult to displace and can lock-out alternative technologies for extended periods, even when the alternatives demonstrate improvements upon the established TIC" (Unruh 2000: 818).

The political resilience of the fossil fuel-based TIC embedded contemporary economies highlights the central problem of path dependency and explains the slow progress of policy adoption to induce a shift toward decarbonization. Inefficiencies created by carbon technologies, such as negative externalities and suboptimal power system resilience, could be mitigated with a systemic reorientation around renewable electricity production. Energy conservation programs not only provide cost savings to ratepayers and utilities, but also enhances reliability and utilities in meeting resource adequacy requirements during times of peak demand (Hoffman et al. 2018). Distributed renewable energy projects can lower costs and improve grid resilience to extreme weather events (IRENA 2016, Lovins 2017). Despite the documented economic benefits, there is still industrial and institutional resistance toward assuming the risk of carbon-based power plant closures, and in some jurisdictions, there are attempts to lock-out appreciable entrance of renewables into the electricity market (Unruh 2000). The TIC framework helps explain how the interactions between technologies, institutions, and firms cause persistence of barriers to clean energy deployment and focuses on macro-level dynamics as opposed to individual- or firm-level decision-making.

The key element of the TIC framework relevant for this project is the co-evolution of public institutions and technological systems. The electricity system inextricably links institutions and private utility firms because electric service provision has been under the purview of public policy authority since the 19th century, as electricity has been deemed a universal service in which citizens should have equal access (Unruh 2000). Because utilities are susceptible to natural monopolization, government intervention is justified to ensure the provision of reliable and safe electricity service and the protection of ratepayers from burdensome rate increases. The electricity market then is a construct of both private wealth-maximizing activity and public formal constraints; behavior in the power sector implies consequences for public and private entities. Through the monitoring and enforcement activities conducted through PUC oversight and the positive feedback processes described above – learning/innovation, coordination across a complex integrated system, growth of adaptive expectations – policy and economic organizations develop concomitantly through interdependency. Reliability standards for large-scale power plants and interconnection standards for distributed generation equipment are two straightforward examples of potentially lock-in producing technical decisions that ingratiate utilities and behavior into certain modes of information processing and rule implementation. Once adopted in policy, the choice becomes the organizing principle governing institutional and industrial behavior alike, raising (a) the cost of switching to an alternative technological system to public and private spheres, and (b) the barrier to entry by low-carbon technologies (Seto et al. 2016). Unruh (2000) explains the synergistic coevolution of organizations and institutional designs based on the dominant technology:

> As the [electrical] system expands, increasing returns mechanisms drive down costs and increase the reliability and accessibility of the system. The increased availability of cheap electricity tends to encourage increased consumption as more customers become connected and acculturated to the system, and innovators in secondary industries invent new applications and end-use technologies. In response to this induced demand, the government regulators build or approve the construction of more capacity to meet expanding needs, feeding a new growth cycle. As this feedback cycle continues, and the scale of the system increases, the technological and institutional forces of lock-in solidify. (p.827)

Regulatory-industrial coordination is necessary to facilitate efficient exchange of energy transactions, so the political ties between power companies and their regulators must be examined in order to answer the question of why state governments vary regarding their policy support for DG integration. Some research has examined energy company lobbying activity directly and finds that fossil fuel corporations and public utilities have generally had greater success at securing agenda control in legislative and regulatory venues relative to renewable energy associations or climate interest groups (Brown 2016, Stokes 2020). *Regulatory capture* has also been considered as an influence on resistance toward DG integration, as regulators and the regulated community share common vocabulary and practices over the course of conducting administrative procedures (Brown 2016, Unruh 2000). Capture theory proposes that regulated industries draw policy designs in alignment with their interests over time through a variety of often opaque mechanisms, such as the "revolving door" phenomenon of former industry chiefs holding positions in public office and the informational asymmetries that tend to favor economic actors relative to oversight bodies (Bo 2006, Carpenter and Moss 2013). Instances of capture and lobbying tend to be driven by the industry's concerns over *reliability*, due to the intermittency characteristic of renewable energy projects, and *rate impacts*, due to cost-shifting or revenue lost to distributed generation (Stein 2016, Stokes 2020).

This project acknowledges the value of these lines of research in illuminating ties between public policy and economic organizations but relegates the question of industry capture and agenda control to studies focused on the individual- and utility-level unit of analysis. The more granular level of analysis is better able to draw causal inferences on the efficacy of utilities' political efforts at inhibiting or initiating policy change in particular jurisdictions and leaves the work of discerning capture and lobbying to other research projects. This dissertation is focused on sources of policy stability in the aggregate-level and instead investigates the interaction of economic conditions and institutional design in determining policy outputs relevant to DG integration across states. While the TIC framework can be used to analyze climate politics at a variety of geopolitical scales and industries, this project focuses on the electric utility policy subsystem.

In emphasizing economic variables and institutional designs in influencing policy outcomes, we must define conceptually the role of presently existing arrangements in producing policy change or stability. Thus far, the chapter has defined transaction costs and increasing returns to demonstrate the path-dependent nature of technological markets and institutions while discussing the relevance to the development of the electricity system. The next section defines the gradual process of regulatory change that has characterized most DG policy developments in the US.

Regulatory Regimes and Policy Drift in the Electricity Subsystem

If path dependence is defined as self-reinforcing processes of increasing returns and risk aversion, we can devise hypotheses on how the institutional matrix and its constituents facilitate the continuity of public policy regimes, and what factors could dislodge institutional inertia to achieve new policy objectives, such as renewable DG deployment in the power sector. Prior to delving into the pertinent policy change theories, we must first provide a definition for regulatory regimes and policy subsystems, as these concepts are informative for describing the sources of policy stability in particular issue areas.

Policy subsystems are constituted by the constellation of public actors, private actors, and institutions involved in the decision-making processes surrounding a particular economic sector or issue area (Berry 1989, McCool 1998, Sabatier and Jenkins-Smith 1993). The subsystems view is useful for examining the interplay between actors and institutions, and the how sector-specific public policies causally influences politics by (a) determining political cleavages and induce certain forms of interest group behavior to achieve policy goals, and (b) determining the accessibility of institutions to interest groups and the ability for external social pressures to motivate institutional change (Lowi 1972). Policy subsystems can be placed along spectra of permeability, density, and malleability. The terms *iron triangle* and *subgovernments* have been used to describe subsystems in which the set of legislative committees, regulators/bureaucrats, and economic organizations have regimented procedures with routinized interactions among relatively few participants, raising barriers to entry by outside or public interests in the decision-making process (Birkland 2006). *Issue networks* describe subsystems with a large number of participants, decentralized authority, and greater opportunities for interest group representation and contestation (Heclo 1978).

Highly technical economic sectors tend to be more insulated from external pressures, leading the electricity subsystem comprised of investor-owned utilities, state utility commissions, and state legislator committees to resemble a *state corporatist network*, in which a few economic actors are heavily involved in policymaking, and state regulators wield substantial agency discretion in their energy pricing and resource planning decisions (Eisner et al. 2006, Howlett et al. 2009: 85). State corporatist networks, however, are not as insular as the subgovernment/iron triangle concept may suggest, because renewable energy advocates and environmental NGOs do have the ability to challenge utility actions in regulatory proceedings. A political arrangement consisting of few actors and specialized technical knowledge does not preclude institutional change, yet there is good reason to believe that policy decisions in tightly knit networks will be more durable to evolving social conditions.

The concept of *policy or regulatory regimes* can be used to contextualize policy subsystems and shed light on the source of resistance to institutional change. If subsystems denote the specific actors and formal procedural constraints shaping the governance of an economic sector, regulatory regimes refer to the broader arrangement of institutions, actors, and *political-economic ideas* that structures human interaction over long time scales, informing both subjective models of reality and objective legal and policy constraints. Eisner (2017) defines regulatory regimes as “a historically specific configuration of policies and institutions that structures the relationship between social interests, the state, and economic actors” (22). Scholars have considered the existence of regulatory regimes at multiple scales. Eisner (1994) used the concept to explain historical paradigms of state involvement in market activities, such as the emergence of the social welfare regime of the 1960s-70s, which imposed restrictions on a wide range of industries to mitigate public health and environmental risk. Other researchers have considered regulatory regimes as the perpetuity of ideas specific to subsystems and economic sectors (Howlett et al. 2009).

This project uses the regulatory regime as a useful analytical tool for describing policy stability and incremental change in the electricity sector. The utility policy subsystem is governed by the prevalent ideas, values, and images of *reliability, affordability, and security*. These ideas have congealed into policy designs and patterns of implementation that appear to best satisfy these conditions through centralized grid planning and a favorability toward baseload power generation, including coal and nuclear, which are capable of providing a steady stream of electricity service. However, in the regime's historical emphasis on the three above values, there has been little room to consider the values of *efficiency, resilience, and environmental protection*, all of which would improve under carefully managed integration of clean energy technologies.

In a state corporatist network such as the electricity subsystem, in which exogenous shocks have not culminated into massive public pressure for renewable energy and DGs, discontinuous change is unlikely, and the regime embodies the values of reliability, affordability, and security at the expense of other values. Since electricity regulation is not characterized by massive lurches in policy marked by critical junctures, we must look to theories of continuous or incremental change to explain the shift in patterns of policymaking within stable regulatory regimes. The utility subsystem represents one such enduring regime, in which the rate-regulation process costs of few players, and major innovations are treated with trepidation due to potential impacts on ratepayers and service reliability emerging from sudden systemwide transformations. Despite the durability of the utility policy monopoly, DG integration policies have significantly diffused over the past few decades through the diffusion of net metering programs and renewable portfolio standards with distributed technology deployment targets. What explains policy shifts within relatively stable regulatory equilibria? The next section examines the theories to help us precisely articulate the causes of regime persistence and inertia.

Analyzing Policy Stability and Change: Regulatory Drift

I now turn to examine how theoretical models of policy change can aid our explanations of stability and gradual change in electricity regulation. Before proceeding, it is important to note that frameworks analyzing policy stability versus change are not mutually exclusive. Despite the seeming incongruity of path dependence models, which suggest durability of existing arrangements, and policy change models, which examine factors influencing transformative rule changes of shifting patterns of implementation, both phenomena can be explained as a function of probability given existing institutional constraints and social conditions. Rather than consider the "right" theory that explains policy stability or change in all imaginable scenarios, we can treat theories as "additive in a certain sense, and thus are characterized by overlapping and complementary features," and there is "no one size fits all" approach to examining the factors of institutional change or resilience (Riccucci 2018: 12-13). Moreover, most analytical frameworks do not rigidly discredit competing theories, rather, theories of policy change tend to emphasize certain elements of the political process and treat institutional change as a combination of structural, behavioral, endogenous, and exogenous factors (Sabatier et al. 2014, Eisner 2017).

For the purposes of this project, the concepts of path dependence and increasing returns explain both *stability* in its function of generating risk-aversion and lock-in, and *change*, in the incremental adjustments spurned by positive feedback, adaptive capacity, and political maneuvering by a regime's actors.

Theories of path dependence and increasing returns may suggest that institutions are robust to evolving contexts and will be resilient to actions attempting to overturn the conventional regulatory regime and utility business model. However, while increasing returns entails positive feedback processes that reinforces prevalent arrangements and produces technological lock-in, it must be cautioned that path dependence does *not* imply that institutions are static or ossified entities, nor does it imply that transformation in policy outcomes is only possible when exogenous shocks disrupt prevalent institutions. The following section describes the models of gradual policy change theoretically compatible with the forces of path dependence and increasing returns in explaining policy change in the electric utility subsystem, with emphasis on three forms characteristic of gradual change in particular: *policy drift, layering, and conversion.* Each process results in suboptimal outcomes due to the incongruity of earlier established formal constraints and recently introduced means to achieve new goals.

If subsystem actors maintain a firm grasp on policy venues and can effectively lock-out the entrance of new ideas, symbolic frames, and interest groups, the prevalent regulatory regime will persist. Stable regulatory regimes with concentrated subsystems have been called *policy monopolies*, in which problem definitions, agendas, and selection of policy instruments remain constant over time (Baumgartner and Jones 2009). Many researchers have developed theories of *discontinuous* or *discrete* policy change by explaining the factors that culminate in comprehensive disruptions of the dominant policy monopoly, establishing a new regulatory regime consisting of new ideas, players, and policy tools. Punctuated Equilibrium Theory explains regime disruptions primarily as a function of exogenous shocks raising issue salience, creating the opportunity for interest groups to advance new problem definitions in policy venues to reconfigure prevailing arrangements (Baumgartner and Jones 2009). However, the domination of an issue area by a specific set of actors for long periods of time characterizes the vast majority of public policymaking, and this is certainly the case in regulation of the electricity sector (Howlett et al. 2009, Cooper 2017, Streeck and Thelen 2004).

Instead of examining the causes of formative critical junctures as in Punctuated Equilibrium Theory, this project focuses on the sources of *relative* stability in electricity regulation, in which policy change occurs through a pattern of incremental adjustments driven by *endogenous behavior* within the policy subsystem, not solely from exogenous shocks.[49] While overarching formal institutional structures remain constant during long periods of *apparent* statis, political actors work within formal constraints to pursue modifications in behavior and policy objectives under formal constraints in the phases of policy implementation and program administration (Streeck and Thelen 2004, Hacker 2004). Path dependence and increasing returns self-reinforce the existence of policy monopolies and increase the difficultly of adopting new ideas and actors, lowering the probability of sudden or discontinuous change. However, theories of gradual change demonstrate that public policy transformations can occur over time whilst maintaining the overarching institutional structure. I will now describe each relevant model in turn.

[49] We might consider both the energy crises and subsequent federal legislation of the 1970s as exogenous shocks, which naturally drove the growth of renewable energy markets and policy changes at the state level. This project does not consider external events to be unimportant in explaining the implementation of policy goals, but this project is more focused on state-level policy change *between* such exogenous junctures to illustrate the variation in state responses to technological and political-economic factors.

Policy drift describes one form of gradual change, in which a regulatory framework becomes unable to adequately address its policy objectives as the policy context evolves. When policymakers fail to update policy instruments in the face of new social conditions, the regulatory regime *drifts* from the reality of social and environmental risk; *drift* refers to the growing gap between a policy's means and ends. We can say that drift is occurring if the regulatory regime is kept in unchanging stasis, or if that regime evolves at an excessively incremental pace, to the point that the regulatory framework no longer organized around achieving the policy goal of risk mitigation.

Drift is driven by subsystem actors to either meet new policy goals or resist adopting new ones, creating a mismatch between formal policies and policy problems. In other words, drift creates a gap between policy goals and their instruments, and "occurs when policy ends change while policy means remain constant, thus making the means inconsistent with respect to the changed ends and hence often ineffective at achieving them" (Howlett et al. 2009: 204). *Retrenchment* is a major component of policy drift, in which political actors seek to weaken a public policy by relegating the state to a marginal role in designing and implementating social programs, usually by overturning core statutes or cutting program budgets (Hacker 2004; Eisner 2017). However, retrenchment entails "active" policy adjustments to the formal components of policy and thus is more narrowly construed than policy drift. Originally conceived by Jacob Hacker (2004), drift can manifest more broadly as "a shift in the context of policies that dramatically alters their effects" (45). In this conception, drift occurs when programs or regulations are hamstrung by outdated statutes and policy frameworks, and the actors within a policy regime actively work against the introduction of new goals, objectives, and interested actors, all of which may build state capacity to address new policy problems emergent from changing environmental conditions. Policy stability in the face of changing conditions would reveal evidence of drift, given that the intent of the original policy is to reduce social risk in arising out of the subsystem's industrial activity. If drift occurs, public institutions lack the resources to carry out the intent of risk protection policies.

Policy drift is conceptually similar to the implementation gap, in which administrators might lack the tools and resources in order to satisfy objectives outlined in statute or policy. Public agencies with limited administrative discretion created by overly prescriptive statutes lack the flexibility to respond to emerging problems within their regulatory domain, hence ground-level outcomes may fall short of policy goals (Epstein and O'Halloran 1994). On the other hand, in agencies afforded greater latitude in formulating regulations, streel-level bureaucrats muddle through policy problems to meet the objectives set in policy, but the design and goals of policy might alter over the course of implementation as a consequence of administrative decisions. However, it should be noted that while patterns of implementation can have a cumulative effect on program objectives over time, *drift* refers to the broader process that results in the failure to of institutions to resolve policy problems (Riccucci 2018). Drift does not only occur in the implementation phase, but also in formal policy changes that weaken the efficacy of earlier statutes and programs. Drift has also been considered the product of policy monopolies' superior agenda-setting power over their regulatory domain; entrenched players are able to secure control over policy venues and engage in agenda-denial tactics to lock-out the entrance of new policy objectives and actors (Eisner 2017). We can consider drift as the product of active political maintenance of existing regulatory frameworks to prevent their restructuring, which might impinge upon the increasing returns and raise the risk proposition to the incumbent regime (Hacker 2004, Riccucci 2018, Eisner 2017). In short, drift is not an accidental occurrence.

Regulatory drift manifests in the electricity subsystem in several ways. To start, aside from a few nascent cases, the utility regulation model prevails in most states, and the basic architecture of cost-of-service rate regulation is intact even in states making innovative strides.[50] This model is increasingly out-of-step with the *risk protection* demands created by climate change. In its "behavioral logic" inherited from the traditional regulatory regime, PUCS and electricity corporations seek to minimize risks associated with affordability, reliability, and security of service. Risk minimization in the traditional political-economic-environmental context was fully compatible with the build-out of grid infrastructure and centralized baseload generation assets; coal power, nuclear projects, and central grid planning all supported the three policy goals listed above. Climate change introduces new social risks. For example, extreme weather events, such as the polar vortex that brought over 30 gigawatts of power generation offline in the Electric Reliability Council of Texas (ERCOT) in February of 2021, demonstrate the need for a *resilient* power supply, in which outages and disruptions can be quickly responded to by drawing from smaller-scale resources.[51] In a more straightforward example of regulatory drift, air quality regulators have tended towards lenience in enforcing power plant emission controls during periods of stochastic operational inefficiencies (Ozymy and Jarrell 2012).

Given the exposure of the grid to climate risks, it is also fair to question whether traditional cost-of-service regulation is capable of satisfying the three traditional objectives. Adaptation risks associated with climate have not culminated in a widespread attempt to modernize electricity infrastructure at a broad scale in spite of environmental and renewable

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[50] Hawaii, for example, is involved in a regulatory reform process to reorient utility regulation around incentives to award beneficial social and environmental performance. New York is engaged in a similar process with the Reforming Energy Vision (REV) proceeding.

[51] Utility Dive, Power experts cite gas constraints as main cause of ERCOT outages, but system planning questions remain. 18 February 2021: https://www.utilitydive.com/news/power-experts-cite-gas-constraints-as-main-cause-of-ercot-outages-but-syst/595255/

energy advocates' best efforts, signifying regulatory drift (Stokes 2020). Net metering policies, interconnection standards, community solar programs, etc. would assist states and utilities in mitigating the impacts of climate driven by fossil fuel sources of energy, but the mass deployment of DGs would entail a systemic shift toward *decentralized* generation. A DG-heavy grid might provide more effective tools for mitigating and adapting to climate risks beyond that of reduced greenhouse gas emissions, such as flexible load management and service disruption response, but path dependence increases the short-run cost proposition for utilities by the negative impact from DG integration on revenues flowing from utility assets. Because the financial risk is greater to utilities, utilities can argue that the financial risk is greater to ratepayers, raising the probability that PUCs will avert risk by punting on policy decisions that would substantially transform the electricity system to one provided by DGs in higher proportions. Regulatory drift characterizes the slow process by which PUCs raise system size and cumulative capacity limits, and alternatively, when PUCs and legislatures decide that the costs of DG integration exceed the benefits, as embodied in the Nevada case discussed in Chapter One.

Two other models of gradual policy change are relevant to explaining change in electric sector regulation. *Layering* involves the imposition of new institutions and policy objectives onto established institutions without displacing them (Streeck and Thelen 2004; Klyza and Sousa 2013). Policy incoherence can result from layering incompatible policies, causing ambiguities or contradictions in implementation. The adoption of renewable portfolio standards embodies layering, as the mandate to generate a from specific technologies to foster a cleaner electricity mix imposed new objectives whilst retaining the cost-of-service regulatory model. One potential contradiction lies in the limitation to construct large-scale renewable generation facilities without ample transmission capacity. Transmission investments and to facilitate energy exchange across the bulk power system is needed to support renewables expansion, but states and regional transmission operators are hesitant to enable expensive investments, especially considering that ratepayers would bear at least some portion of costs created by an RPS (Puga and Lesser 2009). Layering also characterizes net metering policy in the sense that the policy objective of DG deployment is layered on top of the utility regulatory model. Inconsistencies in net metering programs, such as different system size limits for each utility within the same state, may create adverse consequences for equity and hobble program implementation. (Schelley et al. 2017). Conversely, if the DG compensation rate or program cap inhibits utilities from meeting the state's RPS, regulatory drift would be evident.

Lastly, *conversion* denotes a reorientation of the institution toward new policy goals and instruments whilst retaining the formal policy framework. Conversion may involve the adoption of new goals and inclusion of new actors to alter the role of the regulatory body or its core objectives (Streeck and Thelen 2004, Riccucci 2018). Conversion can be driven internally as embedded subsystem actors seek to modify policies to their constituents' benefit, or conversion can be driven externally via legislative action or social pressure (Streeck and Thelen 2004, Eisner 2017). New York's Reforming Energy Vision (REV) initiative might be seen as a comprehensive effort to reorient utility governance toward the promotion of the objectives of equity, resilience, and environmental protection. A key element of REV is the valuation of distributed energy resources (DER), and program designs to reward utilities through rate incentives based on DER deployment targets are currently under development in several states (Trabish 2021). The Value of DER tariff marks a significant departure from cost-of-service regulation that rewards utilities for constructing transmission and distribution infrastructure; the

REV framework actively attempts to enable the shift towards a distributed grid, lowering barriers to greater DG deployment.

In addition to the three forms of gradual change occurring within stable regimes, there is a fourth possible outcome: *displacement* of the established regime with new regulatory frameworks. Displacement, replacement, or elimination of old regimes may require significant top-down policy directive through legislation or national regulatory policy, and hence can be considered as a form of *discontinuity* and would be conceptually distinct from the preceding forms of drift, conversion, and layering.

With the four modes of policy change defined, Hacker (2004) developed a typology of the requisite conditions that would determine the trajectory of the regime or policy based on two dimensions: (1) barriers to internal change or malleability of the formal institutional constraints, and (2) and the status-quo bias of the political environment, or alternatively, the desire for change among the public and interest groups. Displacement occurs when both the political environment and institutional arrangements are conducive to change. Conversion occurs when the political environment is generally uninterested in policy changes and unreceptive to new problem definitions, but the institutional constraints allow interested actors to mold the regime toward new priorities. Layering is the inverse of conversion; if institutional frameworks are rigid and unbending but political support for policy change is high, new regimes will be layered on top of the old. Drift occurs when both institutions are rigid and political support for the introduction of new policy goals is absent. This typology is displayed in the figure below.

Table 2.1: Jacob Hacker's typology on the four modes of policy change (2004: 48).

Political barriers to change	Institutional barriers to change: High	Institutional barriers to change: Low
High	**Drift*** Stable policies remain in place, effectiveness diminished due to changing circumstances (risk)	**Conversion** Policies adapted by actors internal to policy subsystem to meet new regulatory demands
Low	**Layering** New policies established without displacing existing regime, potentially creating incoherence	**Displacement** Old regulatory regimes are eliminated and replaced by new regimes

Because utility regulation is insular in part due to the long-standing regulatory compact and technical subject matter, *drift* characterizes changes utility regulation more closely than the other modes of incremental policy change. To sum up the discussion so far, the theory that political subsystems create institutional inertia through retrenchment and incremental adjustments is evident when considering the example of DG integration policy. While state policymakers may desire to further the objectives of decreased carbon dioxide emissions and increased electricity generation from renewable sources, several political-economic realities stymie comprehensive regulatory change, especially the long-standing construct of cost-of-service regulation that incentivizes utilities to build infrastructure, sell greater volumes of electricity, and insulates utility assets from DG-driven market competition. In attempting to address the regulatory and economic barriers toward DG integration, a state might be required to circumnavigate or directly upend the conventional utility business model but doing so would require an intensive process of reevaluation of rate design and regulatory reform.

New business models realign the value stream to compensate DG's economic and environmental benefits, entailing movement away from the model that solely values electricity for affordability and reliability, the latter concept of which becomes increasingly dated with an aging power grid and heightened incidence of disruptive climate-induced weather events. Outdated technology and climate change present massive *social* risks affecting actors well beyond the utility policy subsystem, but the subsystem is locked-in to regulatory constraints which overemphasize financial risk to utility assets and ratepayer classes in decision-making, leaving environmental risk mostly unmanaged. *Regulatory drift* has led the utility subsystem's logic of risk management *away* from the demands emergent from the present circumstances through its denial to adopt comprehensive reforms to incorporate climate risks into utility ratemaking, altogether diminishing the prevalent regime's capacity to effectuate risk protection. Some jurisdictions may have experienced greater success in implementing objectives of DG deployment by *layering* policies such as community solar onto existing net metering programs, or through *conversion* of utility regulation to system based on environmental and social performance incentives rather than volumetric retail sales. The next section briefly surveys alternative modes for explaining policy change and discusses their limitations compared to an analytical framework of path dependence and drift.

Path Dependence and Drift vs. Theoretical Alternatives

The perspective that public policies gain momentum built around prevalent policy tools and technologies, producing institutional inertia and regulatory drift, stands against other theories of the political process examining the causes of policy changes, or alternatively, resistance to significant change. I highlight three strands of literature that provide competing explanations of the drivers of policy change, including requisite conditions to create transformative restructuring of regulatory regimes.

First, much of the policy change literature tends to focus on the moments of critical disruptions in policy regimes, driven from exogenous focusing events, creating new opportunities for concerted activity by interested pressure groups to advance policy initiatives. Punctuated Equilibrium Theory holds that policy regimes remain mostly stable over time with little change in the terrain of actors, rules, and goals. However, high-profile exogenous shocks such as economic crashes or environmental catastrophes can prime policy venues for interest groups or social movements to articulate new problem definitions or *policy images* (Baumgartner and Jones 2009). Environmental policy in particular has been considered as requiring exogenous shocks to mobilize enough political support to transform the current policy framework. Natural disasters and industrial failures have been posited as prerequisites for rigorous pollution control regimes; environmental risks are not salient until focusing events can meaningfully shape public opinion and attitudes (Birkland 2006). Some researchers suggest large-scale transformation of the energy system is unlikely due to technological lock-in and the political incentives to retain the status quo, making exogenous shocks necessary to mobilize political action to upend business-as-usual (Unruh 2000, Carley 2011). While the Punctuated Equilibrium framework integrates both large-scale rapid change and periods of stability, this dissertation emphasizes the changes occurring during relatively stable policy equilibria. Additionally, in its focus on equilibria and disruptions, Punctuated Equilibrium is less equipped to incisively delineate the gap between previously established policy tools and the risks left unregulated, whereas the policy drift model explicitly seeks to explain the growing disparity between policy goals and regulatory frameworks through the passage of time.

Second, capture theory may provide insights into the ability of economic actors to shape political outcomes. In a scenario of regulatory capture, regulated industries gradually bring an agency's rules into alignment with their own interests through a variety of mechanisms and processes, possibly at the expense of the public interest (Bo 2006, Carpenter and Moss 2013). Agencies with higher degrees of technical complexity and lower salience are more susceptible to capture; hence we would expect public utility commissions to be more likely than other regulatory agencies to promulgate regulations that favor the interest of electric corporations (Brown 2016, Gormley 1983). While this project does not seek to discredit capture theory, I propose that capture as it is typically understood is not the most useful explanatory framework for explaining change in utility regulation, because it does not provide a complete portrait of the multitude of factors influencing policy decisions at PUCs. The natural monopolization inherent in electricity infrastructure development makes "capture" a forgone conclusion, so it is not altogether inaccurate to claim that PUCs are captured by the utility industry. However, I suggest that a more useful approach would be to accept that electricity regulation was always going to be an insular field due to its technical subject matter, and we should examine how *macro-level* political and economic circumstances impinge upon utility policy subsystems rather than examine the insularity of the policy subsystem as a political phenomenon itself.

Third, in a similar vein to capture theory, public choice literature emphasizes the incentive structure facing individual decision-makers. Public choice theorists examine how agents are induced to maintain the institutional status quo due to regulators' need to secure political and economic resources. The shortcoming of this perspective is that it assumes individuals in institutions are purely rational wealth-maximizers who make choices to secure their own advantage regardless of other considerations (North 1990, Eisner 1994). To the contrary, regulators are sensitive to norms and seek to act within institutional constraints to further the organization's mission (Eisner 1994).

This project argues that an analytical lens examining institutional stability or change, with *path dependence* as the mechanism of resistance to policy change and *policy drift* as the observable outcome, is the most appropriate theoretical perspective for studying state-level dispositions toward adopting DG integration policy. The capture theory and public choice perspectives tend to overemphasize the political relationships within the policy subsystem and does not sufficiently explain the role of economic factors and previously established policy regimes in constraining the universe of policy outcomes. Further, capture and public choice theories may underestimate the role institutional structures play in shaping and constraining individual behaviors. By contrast, an analytical framework of path dependence and policy drift situates actors and political relationships within the wider social and economic context, emphasizing the confluence of technologies, formal institutional structures, and the temporality of policy choices in constraining future decisions. Understanding policy change requires an examination of how the political-economic environment bears upon political relationships; individual-level analysis and an examination of rapid comprehensive policy change will fall short in developing a complete picture of policy dynamics and stability in public regulation.

Breaking Path Dependence: Policy Mixes for Regulatory Certainty

Researchers studying carbon lock-in tend to emphasize the need for exogenous focusing events as a prerequisite for institutional reorganization around new policy priorities (Unruh 2000, Carley 2011). So how would advocates break the path dependence of centralized utility power provision? The incremental policy change models of regulatory drift, conversion, and layering demonstrates the existence of pathways beyond formal policy change. Moreover, transformative policy change and breaking away from path dependencies need not require major exogenous shocks or focusing events. Conversion and layering, while less optimal than statutory mandates due to the weaker durability of program or regulatory-level constraints, would give renewable energy interests leverage in restructuring the regulatory compact to incorporate the values of efficiency, resilience, and decarbonization. Doing so would require either public support or amenable PUCs in order to realign the value stream to induce utility behavior away from centralized grid planning.

The upshot is that advocates may not have to start building a pro-DG integration regime through command-and-control mandates; performance incentive mechanisms and well-crafted DER rate design would effectively create new market signals that elevate the value of distributed generation and concomitantly lower the value of fossil-fired electricity. These policy options would resemble *conversion* and weaken the hold of path dependence to utilities by reframing the *risks* embedded in the regulatory compact. Rate and regulatory reform illustrate the possibility of divergent policy outcomes whilst working within the existing arrangements: "institutional changes can occur through the same processes that first established the equilibrium in the first place — processes that involve the firm, market, consumer, and government levels of the industry" (Carley 2011: 731). Path dependencies can be undone through incremental adjustments to the "logic" of regulatory and industrial behaviors through rate reform, modifying enforcement and resource allocations for fossil fuel industries, and emphasizing clean energy technologies in the utility planning process (Stein 2017).

While this project focuses on incremental change, it is necessary to consider the role of certain formative moments that determine policy trajectories across states. Specifically, we must consider the relationship of environmental protection regimes and DG integration policies. We intuitively expect states with robust environmental protection and energy conservation policies to have approximately collinear regimes supporting DG deployment, because if states have altered the value of emitting GHGs and incentivized energy efficiency measures, the financial risk of plant closures and lost revenue is built into the statutory framework. Policies establishing clear objectives to mitigate *environmental risks* has the effect of creating regulatory and market *certainty* for utilities, ultimately reducing the transaction costs associated with innovative technologies and mitigating DG integration (Rogge et al. 2017). By reducing uncertainty through environmental regulation, we would expect less resistance toward DG integration, as utility assets are already ingratiated into an institutional framework that values environmental risk, hence path dependence would not be as forceful in constraining utilities and regulators.

Environmental & Technology Policy in the US Federal System

This section summarizes the relevance of the project to literature on environmental politics and policy in the context of the US federal system, and then briefly discusses the available literature on PUC decision-making. The range of state policy responses to encourage or moderate the deployment of distributed energy technologies finds a parallel in state environmental politics. Not all states adopt environmental constraints onto energy systems or promote the transition toward cleaner fuel sources. Because this dissertation studies renewable energy policy as a tool for driving down carbon dioxide emissions from the power sector, the project contributes to research on the nexus of environmental and energy issues, with particular implications for state-level environmental politics. Research in environmental federalism tends to portray a states' environmental protection regimes under the contemporary era of national polarization and gridlock as a pattern of significant regulatory divergence, in which some states are enabled to advance environmental objectives more aggressively, while others are incentivized to prioritize fossil fuel development at the expense of increased carbon emissions. I suggest that the patchwork dynamic in state energy and environmental regulatory regimes are causally related: economic path dependencies cause drift and institutional friction, leading some states to deprioritize climate objectives over the risks introduced by the systemwide transition toward renewable distributed energy.

States are uniquely positioned to govern the energy sector in the environmental interest for multiple reasons. First, virtually all major national environmental legislation directs states to develop a program for implementing the policy in their state to be approved by the federal administrator, such as State Implementation Plans (SIPs) in the Clean Air Act, giving states discretion in devising their own regulatory regimes for controlling power sector emissions. Second, as discussed at length in the previous chapter, states are responsible for regulating the generation, transmission, and distribution of electricity sold for retail use, giving state policymakers wide latitude in directing the activity of electric utilities and determining the rules for grid access and resource compensation. Taken together, these points illustrate state governments have substantial authority to introduce environmental objectives into regulation of the power sector.

States do not make policy in a uniform manner, and literature describes the variation in state environmental regulations as a "patchwork" of policies (Rabe 2010). Some states are hesitant to adopt environmental quality rules to avoid the economic consequences resulting from a massive reduction of fossil fuel-fired electricity generation. While this dissertation focuses on decisions directly related to DG grid access, the project's findings could be informative for examining to what extent states are able to incorporate goals of environmental protection into regulation of the power sector and contributes to work examining how states layer regimes of environmental protection onto the long-standing regime of electric utility regulation. Each regime consists of separate sets of interest groups and divergent policy objectives; the monetary values and economic incentives for energy conservation diametrically oppose the incentives for energy development. In examining the extent to which states impose environmental policy goals into regulation of the power sector, this project seeks to identify the factors driving governmental institutions to adopt environmental policy objectives despite the financial risks imposed on the regulated industry. There is a need to understand not only the political conditions culminating in critical junctures marked by the adoption of major policies, but also the factors driving implementation of environmental policy in the energy sector.

Environmental policy scholarship holds to a general consensus that the US federal government has gradually become more immobile in developing and implementing environmental policy over the past few decades (Klyza and Souza 2013). Regulating industry and commerce for their environmental consequences in the contemporary era is made difficult as a result of partisan polarization, institutional gridlock, deference to business interests and capture, and prevailing doubts among some policymakers and/or their constituencies over the validity of environmental science and the realities of climate change. As concerns over climate change impacts and air quality issues grow in the twenty-first century, the lack of movement from the US government on environmental and energy issues has driven state governments to pursue policy pro-actively in the absence of national action. The last federal policy change to significantly impact state-level DG regulation was the Energy Policy Act of 2005, which loosely encouraged states to develop net metering programs.[52] The absence of federal mandates left a vacuum of national action and led to policy drift in states that were slow to establish compensation structures and interconnection standards for distributed energy resources. Following the extant literature and proposed theory, we would expect the variation in climate-related political attitudes and industrial composition of states to track similarly with the level of effort and resources states institutions are directing toward economy-wide decarbonization.

Without a coherent federal program establishing nationwide standards, public and private actors at the state-level are exploring paths to decarbonize energy systems by reducing reliance on fossil fuel-sourced electricity generation and by actively promoting the deployment of renewable energy resources in retail electricity markets (Williams et al. 2014). In the federal system, state policies to advance decarbonization diverge based on varying political factors and economic conditions facing policymakers; the "laboratories of democracy" principle enables states to advance policy objectives independent of the national government or other state governments. For states concerned about the impact of fossil fuel-produced externalities, their leaders are compelled to develop regulatory policy that aligns the energy sector with goals of environmental protection. In light of the path dependence model, a state's fossil fuel and electric infrastructural investments together with the policy subsystem locks states into carbon-based energy systems by raising costs associated with integrating distributed generation. Political and economic conditions would have to be aligned to increase the probability that regulatory barriers toward DGs are removed. In states where public support to increase the availability of renewable

[52] It should be noted that the Energy Policy Act of 2005 was not the *only* federal action taken around DGs, but it was the most recent federal action that directed states to reexamine the regulatory environment surrounding the compensation of electricity produced behind-the-meter. The American Reinvestment and Recovery Act of 2009 (ARRA) provided funding for smart grid, energy efficiency, and renewable energy, marking a significant increase in public investment for DGs (Goldman et al. 2011). ARRA undeniably assisted renewable energy market growth, but it did not address the utility business model or compensation structures for DG.

sources of electricity is high, utilities are not dependent on coal power, electricity prices are moderate or low, and the utility market is less concentrated, we might expect DG integration policies to achieve greater success. In states with low public support for renewables, coal-dependent utilities, and concentrated utility markets, path dependence will act as a more constraining force, reducing the probability of adopting DG integration policies.

PUCs and Environmental Interest Regulation

Because of this dissertation's focus on electricity regulation, the pertinent research on the influences on PUC policy outputs must be outlined. Commissions are faced with potentially contradictory pressure points when pushed to incorporate environmental objectives into electricity regulation (Monast and Adair 2013). The institutional role of PUCs had been established to safeguard consumers and system reliability, but the emergence of environmental policies targeting the power sector has significant ramifications for both regulatory tasks. With policies such as renewable portfolio standards and greenhouse gas emissions standards for power plants, commissioners must incorporate new risks posed for electricity suppliers and ratepayers into the decision-making process. Generally, environmental regulations result in some actor bearing the costs of compliance; PUCs will behave in a risk-averse manner to avoid foisting economic burden on suppliers and ratepayers, whilst avoiding risk to overall system reliability (Melody 2016, Monast and Adair 2013). Yet, PUCs are the prime regulatory body with jurisdiction over electricity infrastructure, leaving PUCs to act as the arm of environmental policy implementation in the electricity sector (Dworkin 2006, Sautter and Twaite 2009).

While a vast body of literature on implementation and legislation-regulatory relations contributes to our understanding of administrative procedures and policy outcomes, there has not been a systematic analysis of PUCs incorporation of environmental objectives and risks into electricity regulation. Research is needed to illustrate how PUCs navigate these conflicting pressures, and how they reconcile their traditional role of electricity regulation with the new demands and risks imposed by state environmental policy. This dissertation proposes that, in light of the risks introduced by climate change, *regulatory drift* characterizes PUC decision-making in instances of delay or denial to significantly expand DG programs (Scott 2014). While exploring the variation of the degree of drift across states' environmental regulation of the electricity sector, this dissertation departs with the assumption that some states' regulators are more facilitative of environmental goals articulated by their legislative bodies than others (Rabe 2006).

This analysis would contribute to the extant literature on PUC decision-making, much of which explores whether elected or appointed PUCs engage in pro-consumer or pro-utility behavior (Besley and Coate 2003, Gormley 1983, Brown 2016, Pariandi and Hitt 2018). A strand of the PUC literature analyzes the degree to which "public interest" objectives such as consumer protection or environmental regulation goals prevail in commission rulings (Melody 2016, Sautter and Twaite 2009). Much work on PUCs focuses on regulatory capture and whether decision-making favors utility interests or consumer interests, analyzing PUC behavior through rate case decisions affecting electricity rates (Besley and Coate 2003, Holburn 2006, Fremeth and Holburn 2012, Pariandi and Hitt 2018). This dissertation expands upon this literature by framing PUC decision-making in an environmental context (Dworkin et al. 2006, Monast and Adair 2013, Brown 2017).

Other research examines individual-level regulatory behavior through the principal-agent analytical lens to determine whether certain institutional designs choice results in greater levels of environmental interest decision-making, and if varying principals have any effect on the degree of favorability toward RE integration on the part of regulators (Gormley 1983, Melody 2016). The use of the path dependence perspective of this research places great import on the interaction of institutional design and economic factors. To that goal, this dissertation studies whether the selection process of commissioners - elected or appointed - influences dispositions toward DG policies and responsiveness to certain economic conditions. Literature comparing policy outcomes across commissioner selection types mainly examines how each institutional design results in pro-utility or pro-consumer policy outcomes in terms of rate impacts (Besley and Coate 2003, Gormley 1983). This project will test whether elected or appointed commissioners are more favorable to DG integration policy to determine if different principal-agent dynamics meaningfully influence the probability that PUCs favor policies encourage DG expansion. Whether commissioners appointed by elected officials or commissioners selected by the public are more prone to pursue decision-making in the “environmental” interest, or more vulnerable to regulatory capture, is an area in need of further empirical study (Melody 2016, Dworkin et al. 2006, Brown 2016). However, some research suggests elected commissioners may behave in a more populist fashion by shunning policy alternatives that would feasibly incur any rate increases, whereas appointed commissioners have greater discretion in adopting policy that fosters efficiency and technological innovation (Sautter and Twaite 2009).

Path dependence provides great utility as a conceptual mechanism for describing the institutional inertia evident in state regulatory commissions as a function of technological and institutional lock-in. Each form persists because the installed base of centrally operated fossil fuel infrastructure yields increasing returns to both the regulated community and ratepayers via economies of scale. The theory suggests PUCs would prefer to maintain continued investment and protection into fossil fuel assets to perpetuate cash flows to electric corporations, because "fuel-switching" across distribution networks threatens the prevailing utility revenue model facilitated by PUCs due to the ability of DG customers to avoid infrastructure costs in retail-rate compensation structures (Pierson 2000, Sautter and Twaite 2009, Scott 2014, Brown 2017, Stein 2017). Moreover, if PUCs are able to subvert statutory policy goals by scaling back renewable energy programs, we can characterize the process as regulatory drift. This was the case in Nevada, in which the PUC reduced net metering rates well below the level set in the original law, hampering not only the DG deployment goal of the law, but also the state's ability to meet its renewable portfolio standard.

Observable Implications of Path Dependence and Drift in DG Policy

This section concludes the chapter by describing how this dissertation operationalizes the research question of why states vary in their approaches to regulating distributed energy integration policies. Given the range of variation in state policy environments conducive to distributed generation integration programs, we can safely conclude that path dependence does not have a deterministic character. Path dependence is inherently variable, the degree of which is dependent upon the malleability of formal structures and issue salience derived from the political environment, as explored in Jacob Hacker's typology of the four modes of policy change. State government institutions and political conditions vary, so we would expect the path dependence of state-level regulatory decisions to be similarly variable, facilitating divergent trajectories of policy change governing retail electricity markets.

State capacity for environmental risk protection in the electricity sector is subject to the processes of drift, layering, and conversion, but empirical research is needed to ascertain the range of variation and political-economic factors conditioning the probability of policy change in DG integration. Once this task is completed, we can begin the task of more precisely discerning whether *drift, layering, or conversion* is descriptive of regulatory change within individual states. Because states have established a variety of frameworks and procedures to regulate energy and the environment, and they face different economic circumstances, forms of incremental policy change may vary across states' electricity regulation regimes. Investigating the variance of regulatory and economic path dependence across US states is a key step in determining whether policy drift characterizes the state-level policy environment of DG integration. In testing the influence of path dependence/increasing returns on the probability of pro-DG policy adoption, we will also be able to ascertain whether conversion or layering are more appropriate descriptions of a state's policy developments.

Grounding DG policy research in theories of path dependence and regulatory drift allows us to delineate the essential components of the political-economic factors that constrain governmental institutions, articulating components into variables and testable hypotheses. The empirical portion of the project is divided into two parts: an assessment and analysis of the wider state policy environment and a focused analysis of PUC decision making.

State-Level Policy Environment

Chapter Three models the impact of economic and institutional factors on DG integration policy. In order to measure the state's DG policy environment, it is necessary to first take stock of the relevant suite of policies to support DG integration. The optimal approach is to build an additive index of DG policies with assigned point values to provide a basis for comparison across states, which will serve as the dependent variable of the study. As for capturing regulatory drift, there are two ways to conceivably observe drift with an additive index measure. First, we can characterize states with an unfavorable policy environment for DG integration as exhibiting policy drift due to the increasing risk that climate change presents to society and to the reliability and resilience of the utility system, as exemplified in the Texas winter power failures. This broad conceptualization of drift will be the most easily observable in most cases.

Second and more specifically, if states have enacted legislation establishing emissions reductions goals, clean energy goals, or have adopted similar regulatory policies constraining the utility sector, and subsequently either (a) fail to update existing policies or (b) existing policies face rollbacks or retrenchment, policy drift would be evident. The latter conceptualization of drift characters the Nevada case described in Chapter One. While Nevada's policymakers launched a relatively robust DG policy regime in the early 2000s, programmatic updates were sparse, gradual, and eventually subject to retrenchment. Nevada had established net metering programs prior to the EPACT of 2005, but subsequent revisions to the policy raised the aggregate capacity limit from 1% to 2% of utility peak load in 2011, again to 3% in 2013, and the dissolution of retail rate compensation following the legislatively mandated cost-benefit analysis in 2015. Moreover, the PUC had rejected a proposal to consideration of a solar feed-in-tariff in 2009, punting to the state legislature. The gradual adjustments and eventual vacillation provide a clear portrait of policy drift: despite initial activity to create a market for DGs and adoption of net metering, policymakers balked at attempts to significantly expand DG integration.

The primary independent variable of interest is carbon-based technological lock-in. To capture carbon lock-in, the analysis will model the association of *fossil fuel electric generation capacity* with the state's DG integration policy environment. States with a higher proportion of their electricity supply provided from fossil fuel generation capacity will likely be more risk-averse when faced with decisions to open the distribution system to renewable energy access. If states are path-dependent from fossil fuel infrastructure, we can model the influence of the proportion of coal-sourced electricity within the state's generation mix to reflect the degree of carbon lock-in and determine if higher proportions of coal meaningfully constrain the state policy environment for DG integration.

The second independent variable of interest is the degree of *utility market concentration* of the state. Because this project is grounded in the analytical framework of regulatory regimes, which hold that institutional and economic actors are closely tied due to routinized interactions and specialized discourse, the natural monopolization of electricity markets is expected to play a role in decision-making, with more powerful utility companies bearing more heavily on policy outputs. Therefore, if the theories of path dependence and drift are correct as formulated in the chapter, states occupied by fewer corporations with a greater percentage of market share would be more constrained than states with more fragmented utility markets.

If the discussion on gradual policy change in the utility sector is correct and transformative change is possible absent exogenous shocks, we can examine whether *environmental protection and energy conservation policies* act as a moderating influence on the impact of coal generation and market concentration on the likelihood of DG policy adoption. To determine whether DG-related path dependence is weaker in states with robust regulatory regimes, we must specify whether states have adopted utility-centered regulatory policies such as renewable portfolio standards, energy efficiency standards, and greenhouse gas emissions reductions standards. I advance the general hypothesis that established environmental regulatory regimes moderate the risk-relationship to an extent that policymakers are not as risk-averse to RE integration under stringent utility-centered regulatory regimes, leaving them less constrained by carbon-intensive industries. Therefore, carbon-based path-dependency is less prominent as an influence in decision-making. This is because environmental regulations reduce uncertainty in utility resource planning and internalize negative externalities, mitigating the financial risks presented by higher levels of distributed renewable generation. Institutional inertia in electricity regulation is not as significant a constraint in states that have adopted comprehensive environmental policy regimes that systematically address incorporate environmental risk in governing industry behavior. On the other hand, if states have adopted the foregoing regulatory policies yet exhibit weak policy support for DGs, this would be evidence of drift. In the following empirical chapters, we test the efficacy of these relationships and whether significant interactions are occurring between them. For example, it could be the case that the likelihood of environmental regulatory frameworks is associated with a higher likelihood of DG policy adoption, but conditional upon whether the state has a low degree of utility market concentration. This would comport with the perspectives that drift is caused subsystem retrenchment.

Additionally, the analysis must account for other political and economic factors to ascertain the influence of macro-level constraints. The analysis seeks to capture the effect of changing renewable energy costs using the levelized cost of electricity (LCOE) for solar and wind technologies. Path-dependence may also be an effect of energy costs generally, so the study must also model the influence of electricity rates on the DG policy environment. It is expected that energy cost variables have an inverse relationship with pro-RE integration policy, and this dissertation hypothesizes that falling energy costs for renewable generation mollifies the influence of increasing returns on state policy, hence reducing the path dependence created by the fossil fuel sector. To account for states' broader political environment, the research design can control for partisan composition in the state legislature.

Analyzing PUC Regulations

Understanding PUC decisions separately from the broader state policy environment is necessary for discovering evidence of regulatory drift. To answer the guiding research question of why there is variation in state electricity regulation with regard to policies enabling DG access, this dissertation analyzes PUC rulemaking proceedings. Chapter Four utilizes a similar set of factors as the preceding chapter to maps out the relationship of independent variables carbon-based risk, economic indicators, and institutional variables and DG integration index scores. The PUC-focused portion of the project is interested in determining whether these factors have greater efficacy at the regulatory phase of the policy process in electricity regulation.

Two sets of independent variables can be used to analyze PUC decision-making more carefully, independent of the state DG policy scores. First, because the PUC has administrative discretion in the technical details of DG integration, the analysis is conducive to include technical grid capacity as a variable by determining whether *distribution network hosting capacity* is correlated with pro-DG decisions, with the expected relationship that regulators will perceive optimized grids as more prepared for expanded DG integration. Second, the chapter will include an element of institutional design to determine whether the selection method of commissioners – elected or appointed - meaningfully constrains the regulatory process or increases the probability of a pro-DG policy output. As discussed in the brief literature review on PUC research, it is feasible that electoral incentives and principal-agent relationships result in varying degrees of path dependence and drift. Research suggests that administrative discretion and appointment methods reduce the electoral incentive to avoid potentially costly technological innovations, hence path dependence and drift may be a greater source of resistance in elected than appointed PUCs.

To illustrate the analytical framework for empirical analysis of path dependence and drift in DG integration policy, I have laid out a conceptual diagram to distill the essential variables and relationships under examination below:

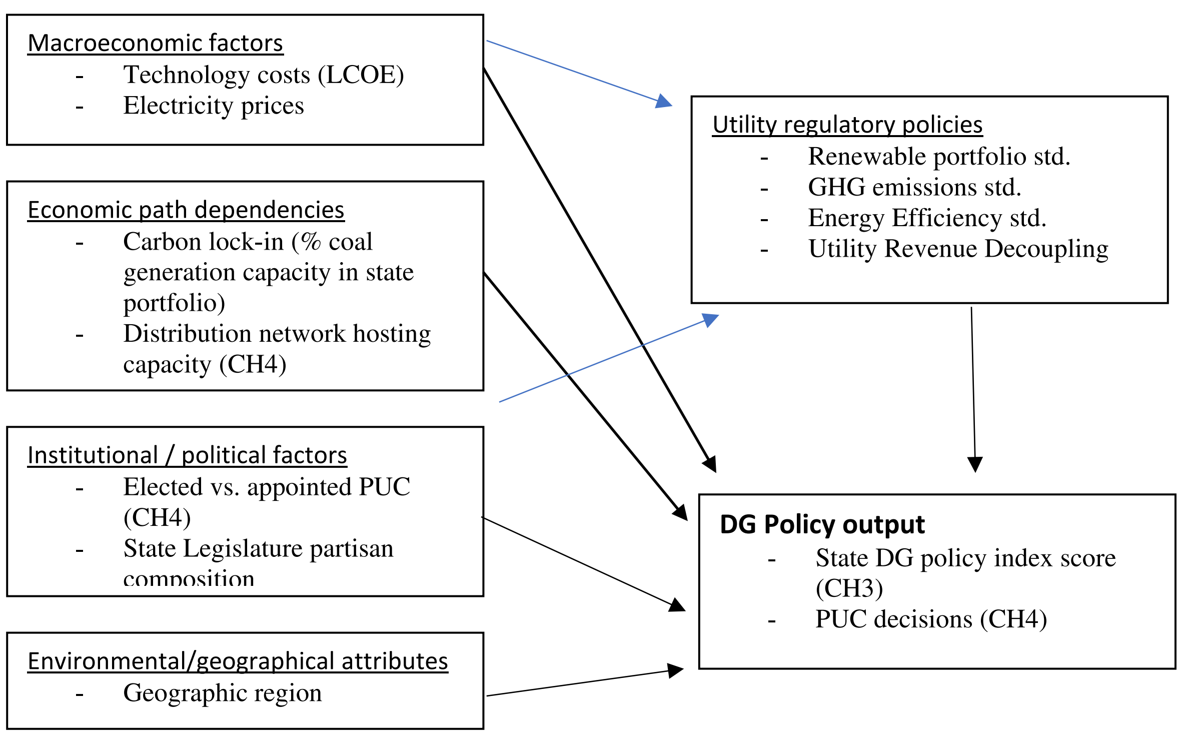

Figure 2.1 Conceptual diagram: relationship of political and economic factors with DG integration policy environment

In the figure, lighter arrows indicate a moderating relationship; utility regulatory policies are proposed to moderate the influence of economic path dependencies and other factors on the DG integration policy environment.

Conclusion

In this chapter, I have argued that path dependence and regulatory drift characterize institutional stability and the incremental pace of policy change in regulation of the electricity sector. Political science research utilizing rational choice and game theoretic frameworks to explain individual-level decisions will fall short in capturing the full institutional context and aggregate-level variance in the causes of policy change. Capture theory, while valid in exploring the effects of political relationships on policy outputs, is not as useful for explaining the variation of path dependence and drift across jurisdictions and overemphasizes the role of relationships in ascertaining causality.

The institutional and macroeconomic levels of analysis are the most appropriate angle to examine electricity policy change because the foundational elements of transaction costs and increasing returns grant extreme importance in the *institutional context* in determining the trajectory of policy change and resistance toward transforming established regimes. Institutional context is a product of broad economic and political factors, all of which are constrained by temporally bound political choices into technologies and modes of economic performance.

The previous section on observable implications laid the groundwork for undertaking an empirical study on capturing the degree and variability of path dependence and regulatory drift across states. This dissertation seeks to map out aggregate-level policy dynamics of DG integration across states and thus utilizes quantitative methods. The next chapter begins to carry out the task of building a research design to empirically determine path dependence and drift by laying out the universe of data and methodology for analysis.

Chapter III

Distributed Generation Access Policy at the State Level

Introduction

The preceding chapter provides an overview for the literature relevant to understanding how path-dependency shapes political outcomes and policy outputs in the context of energy policy. The theory as outlined leads us to expect political actors at the state-level might base their decision-making on the economic returns provided to the policy community from maintaining currently existing energy systems. This project takes the position that institutional designs and economic systems are intertwined, and the theory of path-dependency suggests that institutional actors will avoid making decisions that place the flow of returns from the prevailing economic system in jeopardy. In other words, political actors are *risk-averse* when it comes to adopting policy that is disruptive to the efficient operation of the power system. Understanding the influence risk avoidance plays in understanding energy-related path-dependencies is central for the overarching research question explored in this chapter: why do states vary in adopting distributed generation access policy?

Chapters I and II also discuss the evolution of the electricity grid and explained the mechanics driving the power system's transition from a centralized grid to a more decentralized system powered in greater proportions by distributed generation. With the introduction of new technologies and utility business models throughout the 21st century, some electric power companies and their regulators have been reluctant to allow open access to the distribution system. *Cost-shifting*, *cross-subsidization,* and the "utility death spiral" are concerns emanating primarily from the utility industry that illustrate not only fossil fuel-based path-dependency, but also how grid characteristics interact with the business model of regulated electric corporations.[53] Some utilities and policymakers believe that an increase of distributed generation on the power grid inevitably results in a decrease of economic returns to the utility and extends financial risk to the ratepaying public.

However, while distributed generation is often framed as an existential threat to the utility business model, there is reason to suspect certain policy choices could mitigate risk associated with the electricity system shifting toward distributed generation. Moreover, because states are well-positioned to adopt policy that is potentially transformative of the utility sector, states have a wide degree of authority in selecting policies that enable greater access to the distribution grid. The literature on policy mixes and policy coherence suggests that the adoption of a suite of related policies might allow for a regulatory framework that mitigates the risk associated with structural disruptions for regulated industries (Howlett and Rayner 2007, Stein 2017).

A robust environmental regulatory regime may be related to greater access to distributed generation within states. In pursuing the public policy objective of environmental protection, regulated industries are signaled to modify their operations to meet these objectives. For the utility sector, this notion is most explicit when considering the role of renewable portfolio standards (RPS) in driving down fossil-sourced electric generation and incentivizing greater use of renewable energy. Emissions reductions goals are another tool to drive down the use of greenhouse gas-emitting energy sources. Both RPSs and emissions control policies are instruments that not only reduce the power sector's reliance on fossil fuels, but they also create

[53] "Cost shifting" or "cross subsidization" refers to the fact that customers with behind-the-meter generation are able to offset their own energy consumption without paying grid charges that utilities use to maintain infrastructure, placing higher costs on customers without distributed generation. See Chapters I and II for further discussion. Also see: Wood, Lisa V. 2016. Why net energy metering results in a subsidy: The elephant in the room. *Brookings*. Retrieved from: https://www.brookings.edu/opinions/why-net-energy-metering-results-in-a-subsidy-the-elephant-in-the-room/

an environment of *regulatory certainty* (Stein 2017). States that have built robust regulatory regimes effectively drive a wedge into the institutional path-dependence shaped by energy systems; environmental policies incentivize the adoption of new technologies and encourage the movement toward an energy economy that produces fewer adverse externalities.

This chapter seeks to examine the relationships proposed above. The research on path-dependence suggests that states heavily invested in carbon-based energy sources would be less likely to make the distribution grid more accessible for the interconnection of renewable energy systems. Drawing from the literature on policy mixes, we expect that path-dependence has less of a stranglehold on utility sector policy if the state has also established environmental regulatory policies for the utility sector. This chapter is organized as follows: first, I will describe the index measure that captures a state's propensity toward enabling distributed generation access – the dependent variable investigated in this chapter. Second, I will lay out hypotheses that will test the theory outlined in this section and Chapter II. Third, I will present a description of the data on state-level policy and findings from the hypotheses tests.

Measuring Policy Responses to Cost-Shifting

It will be useful to recapitulate the policy issues surrounding DG deployment to elucidate the value in measuring DG access within states' regulatory environments. In light of the arguments that net metering violates principles of cost causality and equity, this project emphasizes that the appropriate policy design for DG integration is a political question that cannot be solved in a straightforward technocratic manner. Decision makers must determine *values* and weigh *trade-offs* that will affect the apportionment of costs and resources amongst ratepayer groups and utilities. The concern over "overcompensating" DG customers can be boiled down to how grid resources are valued in the rate structure, and arguments over cost-shifting begs the question of whether conventional ratemaking properly monetizes the benefits distributed renewable energy provides to the utility system. The question of resource value leads organizations supportive of renewable energy to dispute the characterization that net metering overcompensates distributed generators. For example, Rocky Mountain Institute (RMI) filed comments in a Utah Public Service Commission (PSC) proceeding investigating the costs and benefits of Pacificorp's net metering program.[54] After conducting a meta-analysis on benefit-cost studies for solar PV devices, they highlighted several aspects of distributed solar to support the position that retail rate schemes might be *undercompensating* DG owners.

RMI organized the DG-derived benefits into several categories, all related to the utility's avoided cost, but studies diverge on assumptions and methodologies into figuring values into the rate structure. First, DG creates energy value, in terms of both market transactions and system capacity, by displacing the need for generation from other resources, such as natural gas, hypothetically lowering costs by reducing operating load. Second, DG reduces system losses, or lost energy as a result of inefficiencies in transmission and distribution lines, because DG produces electricity in close proximity to the point of consumption (27). Similarly, strategic location of DG can defer the need for utility investment in transmission and distribution infrastructure to meet growing demand. Reduction of system losses and deference of T&D investments act as multipliers for benefits related to generation capacity and the environment, because increasing DG allows for lower energy production from fossil fuel sources. Third, DG can provide grid support or "ancillary" services, which includes the implementation of a variety of grid operation tools such as frequency regulation, facilitation of energy imbalance markets,

[54] Public Service Commission of Utah, Docket No. 14-035-114. Electricity Innovation Lab, Rocky Mountain Institute, A Review of Solar PV Benefit and Cost Studies (2nd ed. Sept. 2013).

scheduling generation resource dispatch, and managing operating reserves (33). Infrastructure equipment that has been upgraded with "smart grid" technology could utilize programs designed to manage electricity demand and curb consumption, which could eventually nullify short run rises in marginal cost caused by DG integration in the long-term through technological innovation and higher market penetration. Fourth, DG can effectively be used as a hedge against fuel prices, as renewable cost inputs are not subject to market volatilities like natural gas (35). Fifth, DG can improve reliability and resiliency by reducing network congestion, reducing power outages, and providing customers with back-up power (37). Finally, DG confers numerous environmental benefits, including reduced utility costs to comply with carbon dioxide emissions controls and the reduced public health and ecological costs of mitigating damages from airborne pollutants or climate change (38).

Much present work is being done by renewable energy developers, utility companies, and advocates to designing solutions to the problem of the resultant cost-shift from DG integration driven by net metering. States and utilities might want to avoid raising fixed charges to make up for lost revenue to DG, because raising electricity rates discourages the implementation of energy efficiency and renewable energy programs (McLaren et al. 2015, Lazar 2014)[55]. Some PUCs have looked to imposing new fixed charges only on DG customers, which could result in the unintended consequence of incentivizing grid defection in the jurisdictions that allow it. In this scenario, the customer chooses a competitive supplier separate from their incumbent utility, or alternatively, they install backup battery storage alongside their DG system to enable them to fully self-supply their electricity and go off-grid entirely (Schelley et al. 2017). Instead of raising rates for a class or group of customers, several methods have been proposed to find consensus on

[55] Fixed charges are 'fixed' in that a customer will pay the same monthly amount irrespective of the volume of electricity consumed.

an advanced rate design that would simultaneously support DG deployment whilst minimizing or eliminating cross subsidies. One method is a minimum bill charge imposed on all customers within a rate class could solve the issue of net metering participants avoiding payment into system costs, and this tool would have a modest impact on customer bills on all but the most productive DG systems (McLaren et al. 2015, Lazar 2014). Minimum bills are similar to fixed charges insofar as they are set at a specified amount that does not vary with consumption levels, but they are different because non-DG customers would not pay extra under a minimum bill scheme; nonparticipants would already be satisfying the minimum bill requirement through payment of fixed and energy charges. Net metering participants would have to pay a minor bill only in months when their DG device totally offsets their electricity consumption.

Another promising approach is to incorporate a demand component in the rate that is determined by the level of energy consumption. Demand charges are presently levied on large industrial consumers as a flat volumetric tariff, but this method is not optimal for efficiently pricing the value of electricity from distributed generation (Revesz and Unel 2018). Instead, researchers have proposed dynamic pricing tools in which the costs of DG-sourced electricity are adjusted as a function of time, location, and system demand. Time-of-use (TOU) and real-time pricing sets electricity rates as varying on a daily, hourly, or sub-hourly basis and can more precisely reflect the true cost of operating infrastructure to serve demand at peak times of day (Darghouth et al. 2014; Johnson et al. 2017). For example, in a grid with low DG penetration, a net metering participant with rooftop solar would be credited in higher amounts during mid-afternoon hours when system demand is highest; the ability for a grid operator to draw upon distributed solar resources may allow the utility to save money if they would otherwise need to bring natural gas plants online to meet demand. A locational pricing scheme would reflect system costs more precisely as well, primarily by accounting for the value of deferred distribution infrastructure investments driven by DG integration (Revesz and Unel 2018). DG installations in heavily congested distribution networks may confer a greater cost saving benefit for the utility, for instance (Eid et al. 2014). In both time-varying and location-varying rates, increasing granularity and resolution would result in more efficient price signals, bringing cost causality between customer groups and utilities into alignment. Additionally, it would be relatively straightforward to incorporate social and environmental benefits into a dynamic pricing scheme, as attributes such as avoided emissions are also determined by geographic and temporal factors (Geffert and Strunk 2017).

Several states and utilities are examining how to include these rate design considerations to adjust retail net metering programs for price efficiency to mitigate lost utility revenue. Beyond net metering rate reform, states can also consider the adoption of a decoupling or lost revenue adjustment mechanism (LRAM), in which utilities are guaranteed a rate-of-return based on their performance toward the satisfaction of certain public policy objectives, such as energy conservation or a DG carve-out (Satchwell et al. 2015). A handful of states have gone so far as to reexamine the conventional utility business model based on volumetric sales as an inherent disincentive to invest in efficiency and renewable technologies. New York and Hawaii, for example, have adopted Performance Incentive Mechanisms, or PIMS, which compensate utilities for outcomes they are not otherwise incentivized to achieve, such as social equity, environmental conservation, and resilience (Goldenberg et al. 2020). Other states have acted in the reverse direction. Louisiana, for example, turned to rolling back net metering entirely by crediting net excess generation at the avoided cost rate, reverting to the PURPA-era policy regime.

The goal of this chapter is to place state policy environments on a quantitative spectrum to understand the degree of variation of regulatory regimes governing distributed generation technologies. Once the DG access index is created, we can begin to meaningfully compare the difference in responses between policy innovators, such as Hawaii, and laggards, such as Louisiana. Utilizing a quantitative index measure will allow us to precisely identify the factors associated with pro-DG policy adoption, or alternatively, the factors creating policy drift and political resistance toward DG integration.

Policy Index – Distributed Generation Access

Chapter II defined distributed generation (DG) access policy as measures designed to ease and encourage deployment and integration of DG systems on the electricity grid. These measures include both (a) regulations/statewide standards and (b) incentive structures designed to enable customer-sited systems to connect to the utility system and potentially receive economic benefits. In order to assess the degree to which states enable greater access to the distribution system, this chapter creates an additive index that accounts for regulations and incentives relevant to DG access. I describe the policies included in the index and their relative importance below. Table 1 provides a summary of the policies counted and their associated values.

1. *Interconnection Standards*

Interconnection standards form the bedrock of DG access policy. A state will adopt interconnection standards to develop a clear procedure for electric customers to follow if they are seeking to install an energy system on their property. Without statewide standards, a customer would be forced to deal directly with their electricity provider, where the customer has no guarantee of a transparent or streamlined process. Plus, if utilities are left to devise interconnection rules for their customer base, DG access could vary widely across the state, presenting a potential problem for utility regulators.[56] When a state seeks to adopt interconnection standards, state legislatures often direct their public utility commissions (PUCs) to devise technical details such as system capacity limit, provisions for inverter-based systems, technical screens, and other provisions. State legislation typically only draws up general guidelines and might provide broader policy direction to the PUC, such as stating which technologies/energy sources are eligible for interconnection. The DG access index accounts for a few important aspects of interconnection standards, each listed and described below.

Statewide interconnection standards. First, a state receives a point for having adopted statewide interconnection standards. As mentioned above, statewide rules streamline and standardize the process for connecting to the utility system. A clear process for interconnection allows for greater penetration of distributed renewable energy facilities across the electricity grid.

System capacity limit. States may receive a total of four points for allowing larger system sizes to be interconnection. States receive one point for systems up to 500 kilowatts kW in rated generation capacity, two points for systems up to 2 megawatts (MW) in size, three points for up to 10 MW in size, and four if the limit is beyond 10 MW or if no hard limit is set in place. The larger the system capacity limit, the easier it is for larger energy consumers to install systems to offset their electricity consumption. The range in system capacity limits and associated point values reflects the range in regulations across the states. A handful of states set very low limits for system capacity size and a few states have not established hard limits to system capacity;

[56] Refer to Chapter II for discussion on interconnection rules.

most state rules fall somewhere in between. Also, the mid-range of point values for this sub-category is reflective of the National Renewable Energy Laboratory's (NREL) categorization of policies designed to drive growth in the "mid-market" of renewable energy, which would reflect the demand of many residential and small commercial facilities (Tian et al. 2016).[57] This market segment is crucial to the wider transition from centralized power toward disturbed generation.

Multiple levels of review. The state also receives a point for standards that have multiple tiers of review for different sizes. Adopting multiple levels review allows regulators more flexibility in assessing the ability to handle new generation coming online on the distribution-side of the utility system. Larger systems require more detailed reviews in order to determine whether the point of interconnection on the power system is too constrained to integrate a particular renewable energy project. If a state's interconnection procedure sets different levels of review for different system sizes, that means customers seeking to install smaller systems likely can benefit from expedited or fast-track processes, posing less of a time burden.[58] In general, more sophisticated review processes result in a wider field of opportunities for system interconnection.

National model rules. States receive one point if they have adopted interconnection standards that closely follow the model interconnection rules developed at the national level for distributed systems. The Federal Energy Regulatory Commission (FERC) established rules governing small generator interconnection procedures (SGIP) for systems within federal jurisdiction, in other words, systems that participate in interstate trade as part of an RTO. The SGIP rules also serve as a model for states to incorporate into their own rules, which presents several potential benefits

[57] The data found within the National Renewable Energy Lab 2016 report - Midmarket Solar Policies in the United States: A Guide for Midsized Solar Customers - is periodically updated on NREL's website.
[58] See National Renewable Energy Laboratory: Interconnection Standards. Retrieved from: https://www.nrel.gov/state-local-tribal/basics-interconnection-standards.html

for easing the regulatory burden of interconnecting to the electricity grid. First, states that design policies from national standards will better harmonize with other states' regulations, which for some states can provide greater certainty to regional grid operators for managing energy supply. Second, it's possible that the patchwork pattern of interconnection rules across states reduces policy certainty for utilities with service territories spanning multiple states. to manage the increasing integration of distributed generation onto their systems. National standards provide clear policy signals to electric providers to develop a coherent plan for responding to an evolving grid. Third, national model rules are generally designed to push states to accommodate technological advancements, such as battery storage and updated standards for inverter-based systems. FERC's most recent SGIP outlines procedures for fast-track technical screens for smaller systems and supplemental review for larger systems, streamlining the process for customer-generators seeking to install smaller systems while providing for a clear protocol to interconnect larger ones. In addition to FERC rules, nongovernmental organizations have collaborated with states to develop of statewide standards for distributed energy integration. The Interstate Renewable Energy Council, or IREC, has been engaged with state policymakers and other stakeholders to advance the adoption and implementation of standardized interconnection rules.[59] Similar to FERC's national standard, IREC's model procedures contain multiple levels of review, fast-track provisions, technical screens, and supplemental reviews to ease regulatory uncertainty for both customer-generators and electrical corporations. If states have adopted the national FERC model or IREC's procedures, the state receive a point toward their interconnection score.

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[59] Interstate Renewable Energy Council, Inc., Model Interconnection Procedures (2019), available at https://irecusa.org/publications/irec-model-interconnection-procedures-2019.

2. Net Metering

Most states allow electricity consumers to offset their own energy use with distributed generators installed on their property. Residences or businesses that have installed a renewable energy system are only required to pay the net electricity consumed on electricity bills. If generation from the renewable system *exceeds* consumption, the state might allow the ratepayer to “bank” or rollover credits to the next billing period to offset future electricity consumption. Additionally, many states have paired this policy with an incentive structure that compensates customer-generators for the net excess generation that is fed into the grid provided by renewable energy systems. The compensation structure can take on several forms, described in the list of policy components below. This scheme is called *net metering* and has been the primary mechanism for incentivizing deployment of distributed generation at the state-level. As such, net metering programs take up an outsized influence in determining the DG index score for the states in this project, compromising 16 points, or half of the possible total of 32 points. This project posits that modern interconnection rules and compensation for distributed generation together are the primary drivers of distributed renewable energy deployment, in sum making up 23/32 points, roughly two-thirds of the index value.

Debates over net metering are critical for understanding the political flashpoint the utility industry finds itself in; financially compensating distributed generation has raised concerns across the US that allowing greater proportions of DG on the electricity grid means that a growing segment of ratepayers do not need to pay charges that allow utilities to recoup infrastructure investment costs. The result is that ratepayers without means to offset their electricity consumption are left to shoulder the burden of cost-recovery for utilities, and with fewer total customers paying into transmission and distribution infrastructure charges, that burden would be higher and more concentrated to non-customer-generators. Because of these cost-shifting or cross-subsidization concerns, states have looked to modifying their net metering programs in recent years.[60] While some states are looking to develop more sophisticated methods of incentivizing the interconnection of renewable distributed generators whilst avoiding cost-shifting, other states have rolled back programs or sought to eliminate them. The scoring scheme reflects the direction of the state's direction in amending compensation structures for distributed generation – higher scores indicate a more favorable policy environment for distributed generators. Below, I describe each of the components of net metering policies measured and the values associated with each,

Compensation Rate. The first component of net metering is the method/amount of financial compensation for net excess electricity generation. Under typical net metering arrangements, a customer-generator installs a renewable energy system to offset the property's demand for electricity, and if the energy provided from the on-site renewable system exceeds demand, the system owner receives a credit for every kilowatt-hour (kWh) of electricity produced beyond the amount of electricity consumed on the property. Excess generation credits can then be used to reduce electricity costs by an equivalent amount in the next billing period, assuming that kWh credits are valued at the retail rate of electricity. While the provision of retail-value kWh credits is a requirement for several government and non-profit organizations to categorize a program as "net metering," not all states provide financial compensation for a 1:1 kWh credit that matches net electricity generation.[61] While many schemes allow net excess

[60] Stanton, Tom 2019. Review of State Net Energy Metering and Successor Rate Designs. National Regulatory Research Institute, National Association of Regulatory Utility Commissions. Retrieved from: https://pubs.naruc.org/pub/A107102C-92E5-776D-4114-9148841DE66B
[61] The NC Clean Energy Technology Center and National Renewable Energy Lab define net metering as including 1:1 kWh credit for net excess generation.

generation to be credited at the retail rate in the customer's next billing period, states less interested in providing monetary benefits to excess generation might simply allow customer-generators to offset a portion of their electricity demand. In these arrangements, customer-generators are still able to roll credits over to future billing periods to offset electricity consumption in subsequent months. The perpetuity and ultimate value of credits varies across states, as some allow indefinite credit rollover, while others might roll credits forward until an established date in which credits expire or are reconciled at a pre-determined compensation rate.

State programs can receive four points for the net metering compensation rate. A score of zero means there is no program that allows customers to offset electricity demand or bank credits. One point is awarded for programs that allow an offset for electricity consumption, which is the bare minimum for net metering. Two points are awarded for net metering programs that compensate generation at the *avoided-cost rate*, which is generally lower than the retail electricity rate and is the default payment to independent power producers under PURPA.[62] The avoided-cost rate is determined by state utility commissions. Programs that credit exported generation at the avoided-cost rate are sometimes called *net billing*, such as Arizona's program. Three points are awarded for a few different scenarios that fall between compensating at the default PURPA rate and full retail: (a) if the state has a compensation structure that uses retail electricity as a baseline, but levies demand or fixed charges, (b) if the state has established a phasing-down of net metering incentives but with compensation rates relatively close to retail price, or (c) if states have an alternative compensation structure that incorporates different attributes in the valuation such as locational, geographic, or system-specific characteristics. In any of these cases, the program in pace allows offsets and incentive payments but falls short of a

[62] See chapter one for a discussion on the Public Utilities Regulatory Policy Act (PURPA).

full retail credit guarantee. A policy that guarantees full retail compensation for every participant receives four points.

To illustrate an example, North Carolina credits generation at the retail rate of electricity, so customers earn a 1:1 credit for every kWh of electricity generated to reflect the amount of electricity *not* provided by the utility. Customers can use net excess generation credits to offset electricity costs in subsequent months for up to 12 months. At the end of a 12-month period, the rolled-over credits are then granted to the utility. While this is not uncommon, many states reconcile unused net metering credits annually, often purchasing/cashing out credits at the avoided-cost rate. North Carolina does not require utilities to purchase credits at the end of a 12-month period; instead, those credits are granted to the utility, and customers do not receive incentive payments for unused credits. Still, North Carolina receives four points under the compensation rate component for net metering, since retail credits are awarded for excess generation.

System capacity limit. The next component ranks net metering programs on the allowable system size in terms of the project's nameplate capacity, which is expressed in terms of rated power output in wattage. As in the compensation rate and capacity limit for interconnection, states can earn a possible four points for system capacity limit, with larger values reflecting eligibility for larger systems. The sizes are valued differently in this index from interconnection limits, because interconnection rules generally seek a simplified process for systems of a wide variety of project sizes, while states or utilities might balk at compensating distributed generation from large renewable projects due to fears that utilities would be unable to recover infrastructure costs with high proportions of renewable electricity which do not translate into utility revenue. However, it must be noted that capacity limits are often implemented due to the high technical demands posed by progressively larger systems.[63] A state gets zero points for setting limits as low as 25 kW. States earn one point if the system capacity limit falls within a range of 25 kW to 100 kW and two if the state allows systems above 100 kW and up to 2 MW. States with a net metering capacity limit over 2 MW and up to 5 MW receive 3 points. States that allow systems up to 10 MW or place no limit on system size to participate in the net metering program receive the full four points.

A few states express capacity limit in terms other than nameplate capacity, and instead express the limit as a percentage of the ratepayer's on-site demand. States that allow a system to be sized to meet 100% of the property's energy requirements receive one point, those allowing the system size to meet 120% of on-site demand receive two points, states allowing systems to meet up to 150% of energy requirements receive three points, and systems above 150% of demand or no limit receive four points.

Aggregate Capacity Limit. Most states impose a limit on the amount of distributed generation that may earn credits for net excess generation. This aggregate or cumulative capacity limit is usually expressed in terms of a percentage of utility demand. More precisely, investor-owned utilities are required to accept net metering applications until net metered systems reach a certain percentage of average peak demand. However, some program limits are expressed in terms of cumulative nameplate capacity, i.e., 350 MW. Since this is less common, I calculate the nameplate capacity amounts as a percentage of the average investor-owned utility peak demand for states that express capacity limits in nameplate capacity using data from the Energy Information Administration (EIA). Once the threshold is reached, utilities are no longer required

[63] Shaeffer, Paul 2011. Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues. Regulatory Assistance Project. Retrieved from: https://www.raponline.org/wp-content/uploads/2016/05/rap-sheaffer interconnectionofdistributedgeneration-2011-09.pdf

to offer the program, or the utility commission may consider a reassessment of the aggregate capacity limit or other components of the net metering program. States can earn a possible three points in this category. Zero points are awarded if the limit is set at 1% average peak utility demand or lower. One point is awarded if the limit is set between 1.1% and 3% peak demand. States earn two points for setting the aggregate limit between 3.1% and 5%. If the state sets no clear limit for cumulative capacity, the state receives 3 points.

Meter Aggregation. States that adopt meter aggregation allow multiple distributed systems on a single parcel or contiguous/adjacent properties to be aggregated, in which the electricity consumption or production is measured as if there were only a single meter. Aggregation is useful for a variety of conditions, including (a) for large tracts in which multiple energy devices are often necessary such as agricultural properties, (b) multi-site properties with a single owner such as government complexes, or (c) properties with more than one tenant such as multifamily housing.[64] Beyond these arrangements, meter aggregation can also facilitate *virtual net metering*, in which a renewable system is allowed to offset the electricity use of multiple property owners off-site. Some virtual net metering (VNM) rules might require the properties to be contiguous or abutting the property with the distributed energy project, while others may simply require the properties aggregated lie within the same utility service territory. States can receive up to two points for authorizing aggregation or virtual metering: one if the aggregation applies only to certain customer types or properties, such as public buildings or agricultural customers, and two points if meter aggregation is unrestricted by customer type. Meter aggregation is a regulatory prerequisite for the next policy: community renewable energy.

[64] Institute for Local Self-Reliance, Aggregate Net Metering. Retrieved from: https://ilsr.org/aggregate-net-metering/

Distributed Generation Adder. To capture positive policy change that does not neatly fit within the parameters outlined above for interconnection and net metering policies, I include a category that allows for additional points to be added onto the state's base score. The inclusion of this category means that a state may exceed the possible base score of 32 points if it aggressively pursues distributed access policies within the 2012-2018 timeframe. This category is useful for incorporating policies that enable the integration of distributed renewable energy but are separate from interconnection or net metering in significant ways. One major example is the feed-in tariff, described below. States may also earn points for adopting community choice aggregation, a policy that allows municipalities to procure renewable electricity from providers outside the incumbent utility, or for adding a new technology as eligible for streamlined interconnection, such as battery storage.

Community Renewable Energy. Also called *shared renewables* or *community solar*, community renewable energy programs have gained much attention in the energy policy community in recent years. If VNM is allowed in the state, members can opt-in or subscribe to a renewable project sited on the distribution system intended to provide electricity service to residences or businesses. Subscribers would "own" a portion of the renewable facility as if the project were sited on their property, allowing them to offset their electricity consumption and potentially earn net metering credits to use against future electricity bills. Community renewables programs are advantageous for moderate to low-income households who might not have the financial means or property characteristics to purchase/lease or install a renewable system on-site, but they can still share in the benefits of renewable electricity by participating in a community solar program. Similar to meter aggregation, states can receive two base points for this community renewable energy: (a) one for having implemented a pilot program or a limited-basis program, for example by customer class, and (b) two for having a statewide community renewables program. In addition, similar to how net metering scores are calculated, I include an "adder" column for community renewables since there are many ways in which shared renewable energy may be modified and expanded. States may receive additional points if they adopt significant modifications to shared renewables programs, such as raising incentive amounts, expanding project/participant eligibility, raising program caps, and other components.

Feed-in tariffs. While similar in design, net metering programs differ significantly from feed-in-tariff programs. *Feed-in tariffs*, or FITs, provide direct incentive payments on a per-kWh basis for electricity provided to the electricity grid from renewable sources. Participants in a FIT program are paid as if they were utility providers, since they are directly compensated to energy provided to the grid. The value of FIT payments is calculated to reflect the "non-energy" attributes of renewable technologies, such as environmental benefits, resiliency or reliability, and deferred infrastructure costs. Because renewable generation is compensated at a fixed dollar amount per kilowatt hour, FITs are also called *renewable standard offers*. While fixed, incentive amounts might be set differently by technology type and system size. In Vermont's Standard Offer Program, solar systems receive 13 cents per kWh and biomass systems receive 12.5 cents per kWh. Small wind systems receive 25.3 cents per kWh while large wind systems earn only 11.6 cents per kWh.[65]

Net metering is separate from renewable standard offers because net metering participants are not guaranteed direct performance-based incentives; they are only guaranteed a right to offset a portion or all of their electricity demand, with some states cashing out net metering credits. Additionally, FITs vary widely in their application. Tariffs can have different

[65] Vermont Standard Offer Program. Database of State Incentives for Renewables and Efficiency, North Carolina Clean Energy Technology Center

term lengths with power contracts often ranging from 10 to 20 years, or they can be tied to public policy objectives such as deployment targets for renewable technologies. FITs are also not as common as net metering programs in the US: while about 44 states have established rules for DG compensation, seven have adopted feed-in-tariffs, with only four programs still operational. However, there are significant number of utilities offering renewable production-based incentives voluntarily, but this project is focused on understanding the drivers of state-level directives.[66] States are less likely to pursue FITs than net metering as FIT incentives are generally set higher than the retail price of electricity, imposing a greater burden on the utility or state. Since FITs are designed to advance policy objectives such as renewable deployment, more robust objectives are paired with higher incentive payments. In the state index score, states receive one point for having adopted a FIT for renewable energy. This is counted in the "DG adder" column for access policies, effectively adding onto the point subtotal for state net metering policies. For example, if a state offers a FIT in addition to full retail net metering, the state would effectively receive five points for compensating renewable generation.

3. *Other Distributed Generation Access Policies*

Third-Party Ownership and Financing. Not at all states have adopted ownership models that maximize the opportunity for residences and businesses to install distributed generation projects. Particularly for small businesses or low-income households, installing on-site solar or other renewable system may be prohibitively expensive. Allowing third-party organizations to own and install distributed generation projects enables ratepayers to circumvent high capital costs through innovative financing arrangements. States may earn three points for the third-party

[66] Feed-in-Tariffs (FiTs) in America, n.d. PV Magazine. Retrieved from: https://www.pv-magazine.com/features/archive/solar-incentives-and-fits/feed-in-tariffs-in-america/

ownership category. First, one point is awarded for states that allow ratepayers to enter into power purchase agreements, or PPAs, with renewable energy developers. PPAs enable customers to purchase electricity from a renewable system owned by the private company through a long-term contract, typically in periods of 10 or 20 years. In addition to benefiting customers by avoiding the upfront cost of directly owning the project, PPAs offer stability and predictability by presenting a fixed price based on the project's power output. Second, states earn a point if they allow third-party leasing, in which a private renewable developer owns and installs the system, and the customer purchases the electricity produced. The private developer is paid back through leasing terms, often a fixed monthly payment, unlike PPAs which might vary by the project's electricity production.[67]

Third, states can receive a point for adopting Property Assessed Clean Energy, or PACE. PACE is a financing tool that allows electricity customers to enter into long-term agreements to pay back the cost of renewable energy or energy efficiency equipment through a special levy on their property tax bill. Before PACE can be implemented, the state assembly must first pass legislation that authorizes local governments to grant themselves bonding authority to finance the program. If county or city governments adopt authorizing legislation, a third-party administrator is then allowed to assess property values and enter into PACE contracts with potential customer-generators. While a few PACE programs for residential properties do exist, they are more difficult to implement due to a variety of financial and regulatory factors, and commercial PACE programs, or C-PACE, are far more common.[68] These ownership and financing models indicate

[67] AEE 2017. Expanding Corporate Access to Advanced Energy: Policies to Meet Growing Demand from Corporate Buyers. Advanced Energy Economy.
[68] Property Assessed Clean Energy Programs, n.d. Office of Energy Efficiency and Renewable Energy, U.S. Department of Energy. Retrieved from: https://www.energy.gov/eere/slsc/property-assessed-clean-energy-programs

state's favorability toward customer-sited renewable energy, so it is sensible to include them in an analysis of state policies toward distribution grid access.

Distributed Generation/Renewable Carve-Out. Many states' renewable portfolio standards (RPS) contain provisions that require utilities to procure a certain amount of electricity from renewable energy or distributed generation projects. States interested in decarbonizing the electric grid pair RPS with technology deployment targets in order to accelerate the growth of a power grid supported in greater proportion by distributed generation as one avenue toward reducing state reliance on fossil fuel-based sources of energy. Deployment targets might be expressed in terms of a percentage of utility load – such as Colorado's requirement that 3% of electricity generation come from distributed sources by 2020 – or they might be expressed in nameplate capacity – such as Massachusetts's requirement that retail suppliers procure 1600 MW of solar facilities by 2020.[69] States earn one point for having a technology carve-out, but they might earn additional points in years that lawmakers raise deployment targets.

Permitting Restrictions. The index accounts for policy changes that affect the permitting process for renewable systems, such as the imposition of minimum setback requirements, prohibiting HOA restrictions on installations, regulations that block projects from interfering with the "character" of the area, or authorizing local authorities to site specific projects. Since there is a catch-all category for capturing siting restrictions, this policy does not have set components. If a state adopts policy that removes or disallows siting/permitting restrictions, the state earns one point, and one point is removed if restrictions such as setbacks or moratoria are adopted.

[69] From the Database of State Incentives for Renewables and Efficiency.

Distributed Generation Incentives. Finally, the index captures policy changes affecting financial incentives for distributed generation technologies. Similar to the treatment of permitting restrictions, states earn one point for each change that increasing funding or incentive amounts for renewables, including the adoption, extension, or expansion of tax credits, loans, grants, or other incentives. Negative points are given if incentives are repealed. This project tracked the changes to incentives for solar, wind, biomass, geothermal, and energy storage from 2012-2018. See Table 3.1 below for a summary table on the set of policies and associated point values.

Table 3.1 State-Level Distributed Generation Policy, Index Values

Policy Type	Component	Points	Subtotal
Interconnection	**Statewide Standard**	**1**	7
	No	0	
	Yes	1	
	System Capacity Limit	**4**	
	50 kW and under	0	
	Over 50 kW - 500 kW	1	
	Over 500 kW - 2 MW	2	
	Over 2 MW - 10 MW	3	
	Over 10 MW or no limit	4	
	Multiple Levels of Review	**1**	
	No	0	
	Yes	1	
	National Model Rules	**1**	
	No	0	
	Yes	1	
Net Metering	**Compensation Rate**	**4**	15
	None offered	0	
	Consumption offset allowed	1	
	Avoided cost rate	2	
	Above avoided cost/NEM successor tariffs	3	
	Retail rate	4	
	System Capacity Limit	**4**	
	Up to 25 kW	0	
	25 kW - < 100 kW (or 100% on-site demand)	1	
	100 kW - < 2 MW (or up to 120% demand)	2	

	2 MW - 5 MW (or up to 150% demand)	3	
	10 MW or no limit	4	
	Aggregate Capacity Limit	**3**	
	1% peak or lower	0	
	1.1-3% peak demand	1	
	3.1-5% peak demand	2	
	Greater than 5% or no limit	3	
	Meter Aggregation/Virtual Net Metering	**2**	
	None allowed/unclear status	0	
	Allowed for certain customers	1	
	Allowed	2	
	DG/NEM Adder*	**1***	
	Community Renewable Energy	**2**	
	No program	0	
	Pilot program	1	
	Active statewide/major utility program	2	
	Community RE Adder*	1*	
Other DG Policies	**Third-Party Ownership/Financing**	**3**	10
	Leasing	1	
	Power Purchase Agreements	1	
	Property Assessed Clean Energy	**1**	
	Permitting Restrictions*	**1**	
	Restrictions imposed	-1	
	Restrictions removed/prohibited	1	
	DG/RE Carve-Out*	**1**	
	None	0	
	Adopted or expanded	1	
	DG Incentives*	**5**	
	Solar	1	
	Wind	1	
	Biomass	1	
	Geothermal	1	
	Storage	1	
Base Total			32*

*Indicates additional points may be added for policy change enabling greater DG access. Several state-year scores exceed the base value of 32 points.

Distributed Generation Policy Index – Breakdown of State Scores

This section describes the variation across state's scores using the index measures summarized above, which attempts to capture the state-level policy favorability toward distributed generation access. After providing an overview of the research findings, I provide some preliminary analyses on the distribution of states scores and the magnitude of policy change over the time period. Then, I lay out hypotheses to be examined for the remainder of the chapter.

Dependent Variable

This chapter took inventory of all substantive changes in the relevant policy areas defined by the distributed generation access index over a seven-year period, from 2012 to 2018. 2018 is the end point for the dataset because this is the year that most finalized utility and electricity data are available from the EIA. Many states undertook the task of amending and updating policies governing distributed generation access during this time period. The primary source of data for the index were state legislative websites, which keep records on enacted laws for each legislative session. To simplify the search for policies, the index also utilized resources from governmental and non-profit organizations that maintain databases on distributed generation policies, including the National Renewable Energy Laboratory, Advanced Energy Economy, the North Carolina Clean Energy Technology Center, the American Council for an Energy Efficient Economy, the World Resources Institute, and the Center for the New Energy Economy. For policy changes that were implemented through regulation, I looked to public utility commission websites and sorted through electric utility dockets, focusing specifically on rulemakings for distributed generation policies.[70]

[70] See Appendix A for a description of the methodology and sources for collecting policy data.

Policies were accounted for in all 48 contiguous states. Alaska and Hawaii were excluded from this project due to a few interrelated factors. First, Hawaii and Alaska residents are faced with the highest energy costs in the US. In terms of electricity rates, Alaska ratepayers paid approximately 19.36 cents per kWh while Hawaiians pay 29.38 cents per kWh in 2018, a good deal higher than the national average of 10.53 cents/kWh that same year.[71] Alaska's population also is predominantly rural, and rural ratepayers in the state often face electricity costs three to five times higher than their urban counterparts.[72] Second, fossil fuel industries in each state look markedly different from the lower 48, and both states' power sectors are partially reliant on petroleum, a characteristic endemic to the non-contiguous states. Almost half of Alaska's electricity portfolio is supplied by natural gas and 12% is contributed from petroleum, while over two-thirds of Hawaii's electricity mix is reliant on imported petroleum. Third and most significantly, each state operates within an isolated infrastructure; neither is connected to a regional power grid. Because of this, it would be difficult to develop a generalized analysis of the factors driving distributed generation policy against political headwinds for these two states because of the particular engineering or regulatory challenges they face in transitioning to a distributed grid in the absence of a regional power network.

Univariate Analysis

By scoring 48 states on a suite of distributed generation policies across seven years, the index has a total number of 336 observations, or an n of 336 state-years. This section provides some descriptive statistics on the range of values, average amount of change in state scores, and

[71] EIA 2019. Average Price of Electricity to Ultimate Customers by End-Use Sector by State. Electric Power Annual report, 2018 and 2017 data. Energy Information Administration.
[72] EIA 2019. Alaska State Profile and Energy Estimates. Energy Information Administration.

information on high, low, and median cases. As described earlier, if a state receives the maximum points for each of the fixed policy components, the state can receive a score of 32 points using the index measure. However, because states can earn additional points for pro-distributed generation policies that fall outside the fixed components – such as policies that improve upon net metering, community renewables, permitting, or financial incentives - states may receive a higher scoring than the base value of 32 points.

The average score for all observations in the dataset is 20.91. Taking the yearly averages show that, on average, the policy environment for distributed generation (DG) access slightly improved across the US. The average for 2012 is 18.46, while the 2018 average is 22.88, revealing a steady four-point increase. While the nation as a whole did not lurch forward in enabling DG access, a few states in the northeast and the west coast did show major policy change during this time. The states that experienced greatest change were Connecticut and New York, whose scores both increased a sizable 20 points from 2012 to 2018. California is not far behind, adding 19 points over the seven-year period. Interestingly, these are all states who had well-established regulatory frameworks for the integration of distributed systems prior to the first year in the dataset, suggesting that state decision-makers may perceive pursuing improvements to the DG policy environment worthwhile if mechanisms to facilitate DG interconnection and compensation are already in place. In terms of rate of change, one midwestern state and one southern state stand out from the pack. Minnesota experienced a score change of 15 points, mostly due to the adoption of modernized interconnection standards, the implementation of a robust community solar program, and the investigation of a Value-of-Solar Tariff (VOST) to succeed net metering, which would essentially function as a feed-in tariff. Virginia is proving to be a clean energy leader in the southeast, adding 13 points to its score in part by pursuing comprehensive clean energy legislation in later years in the set, which contained provisions related to grid modernization, community solar, and energy storage.

Other states did not register much policy activity from 2012-2018. Many states in the Mountain West, Midwest, and Southeast did not pass much legislation to enable greater DG access. Idaho's and Wyoming's scores did not change during this time. Other states, such as Nebraska and Delaware, made minor improvements, netting a one-point increase over seven years. Some states rolled back DG or renewable energy policies, resulting in a net negative score for the time period. Oklahoma and Kansas lost seven and five points respectively, in part due to wind facility setback requirements. Louisiana lost points for shrinking renewable system tax credits and for nixing retail rate net metering in the state. A small number of states experienced vacillation. Nevada, discussed in the first chapter, lost points for repealing retail net metering but regained points for reinstating it and investigating energy storage as a part of the utility procurement process. Utah made score gains by adopting PACE and technology incentives, but then lost points by contracting its net metering program.

The highest-scoring state in the dataset is California, with an average DG score of 39.6 and a 2018 DG score of 50. California regularly seeks means to boost deployment of distributed renewable systems, in line with the state's environmental objectives of reducing carbon emissions from the power sector. New York is a close second with an average score of 36.1 for all years and a score of 47 in 2018. The two median cases for average DG score are Indiana with a score of 21.9 and New Jersey with a score of 22.4. Each state pursued vastly different trajectories across the time period, resulting in a significant divergence in their averages from their end-year rankings; Indiana received 19 points in 2018, dropping the state's rank five places, while New Jersey finished the sample by jumping eight places from 25th to 33rd. The two median cases for 2018 are Arizona and Iowa, both with a score of 23. The lowest-scoring case is Alabama with an average score of 3.86, and a low point of 3 from years 2015 to 2018. From the lowest to the highest state-year score, the range of values is from 3 at the lowest, which belongs to Alabama and 50 at the highest for California. The standard deviation for the observation set is 9.2, indicating relatively high dispersal of DG index scores across state-year observations.

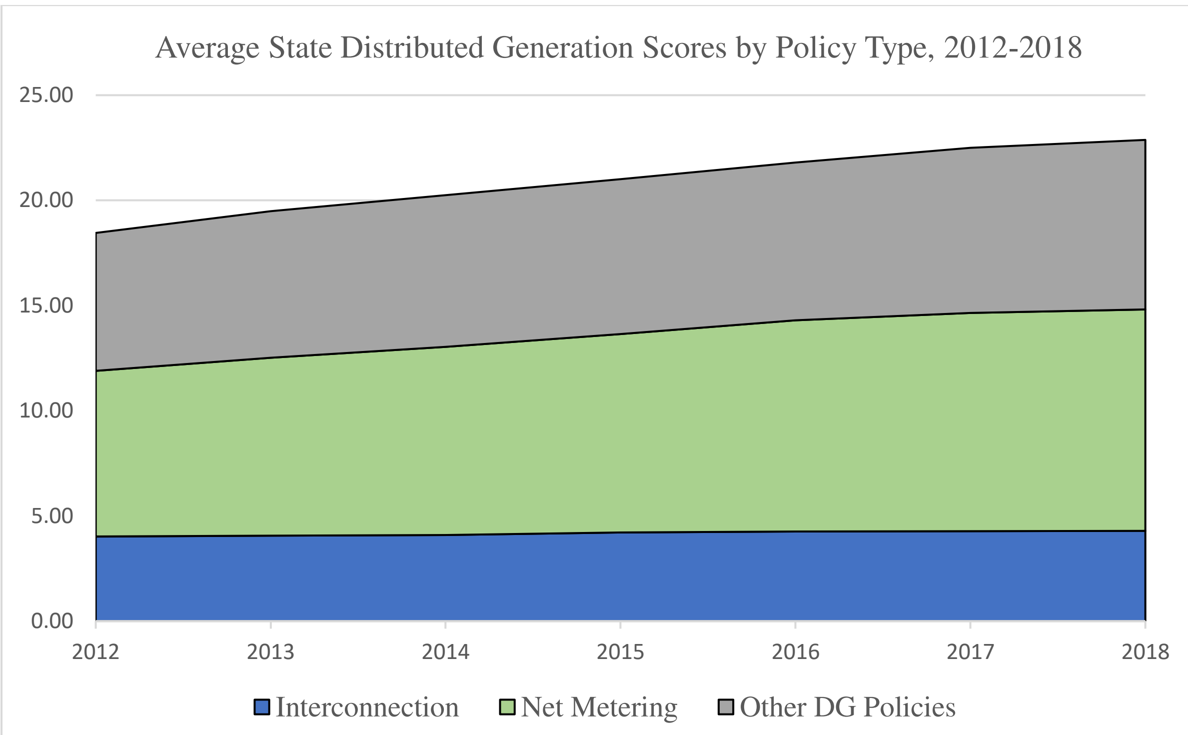

Figure 3.1 Change in DG Access Policy Scores Over Time

Figure 3.1 above displays the trend of index scores throughout the time period, with the three categories of interconnection, net metering, and other policies broken into separate segments to reflect the relative proportion of the overall score averages. Note that the net metering segment also reflects policy change regarding community renewable energy. Interconnection policies were not greatly improved from 2012 to 2018 on average, while net metering and other DG access policies saw greater increases. Displaying the average scores as an additive stack of the three policy types gives us an idea of the weight each policy carries in measuring the state's distributed generation policy. Interconnection rules are displayed at the bottom of the stack and has the lowest point value for the three categories. Net metering is the middle layer and has the highest possible point value; states with net metering programs that increase distribution accessibility and provide higher incentive payments to behind-the-meter generation will most likely place in the higher range of DG scores.

Bivariate Analysis

The preceding section outlined the dependent variable – DG access policy - and the components to measure DG policy at the state level. Per this chapter's earlier discussion, the expansion of distributed generation introduces certain risks into the utility system in the form of cross-subsidization, and this project investigates the possibility that path-dependency created by the long-standing utility regulatory regime constrains state decision-making from accelerating the adoption of renewable distributed systems too quickly. In this section, I first present a set of hypotheses to investigate why states vary in their favorability toward increased DG access. Second, I describe the independent variables to test these hypotheses that might potentially explain state resistance to adopting favorable DG policies. Then, I present results from bivariate analyses and provide preliminary findings to begin shedding light on the influence of path-dependency.

Hypotheses & Independent Variables

1. *Utility Market Concentration*

In determining which factors might drive states to adopt greater access for DG, I first consider the role played by electric utilities. Considering concerns over cost-shifting and losses in utility revenue, it is plausible that utilities with a greater degree of market concentration would be more pro-active in thwarting efforts to open their distribution systems up to further access by customer-sited renewable projects.

H1: States with greater utility market concentration will have *lower* DG access scores.

To test this hypothesis, I gathered EIA data on utility customer counts. Utilities are required by law to report a wide range of information to the EIA.[73] For this analysis, market power is separated into three categories: (a) competitive, in which no single utility has an outsized customer base, (b) monopoly, in which a single utility serves at least 75% of the state's residential population, and (c) duopoly, in which two utilities serve at least 75% of the residential market share.

2. *Structure of Electricity Markets*

In addition to market concentration, I present a hypothesis that accounts for the wider energy market environment. While most states use conventional rate-regulation which allows electrical corporations to own all aspects of the delivery systems, some states have adopted electricity "deregulation" or "restructuring," which allows independently owned competitive retail suppliers to compete alongside the utilities who own transmission and distribution infrastructure. Energy

[73] Operational and sales data are available from EIA form 861. Retrieved from: https://www.eia.gov/electricity/data/eia861/

market competition means that customers have choice of their electricity provider, albeit the ability to switch service from the incumbent utility entails minimum demand requirements. Sixteen states, a third of the states studied in this project, have implemented electricity restructuring. For the similar reasons as *H1*, I expect states with retail electric competition to be more favorable toward distributed energy:

*H2: S*tates that have implemented restructuring/retail choice for electricity markets are associated with *higher* DG access scores.

Traditional, vertically integrated regulatory models foster more consolidated electricity markets, because established public service corporations' control over both the delivery system and the energy produced within the supply chain. Vertical integration precludes the participation of competitive energy suppliers, making it more likely that ratepayers are dependent on centrally operated power plants. Despite this expectation that vertical integration causes lower DG index scores, it must be noted that customers do have avenues to purchase power from distributed sources in traditionally regulated states. Investor-owned utilities are tasked with administering net metering programs and interconnection tariffs, so reduced market competition does not necessarily mean that customers have fewer opportunities to consumer electricity from distributed sources.

3. *Regulatory Policy Environment*

The next set of hypotheses is meant to capture the regulatory environment in which utilities must operate. This captures environmental and conservation policies meant to drive utilities toward a more efficient and cleaner electricity system. It is expected that a regulatory environment that inhibits utility behavior in this way gives policymaking bodies greater ability to break from fossil fuel-shaped path dependencies.

H3: States with energy efficiency resource standards (EERS) will have *higher* DG access scores.

EERS imposes requirements on utilities to reduce demand, sometimes on an annual basis as a percentage of peak demand for a selected base year, or as a reduction from the prior year's demand.

H4: States with revenue decoupling will have *higher* DG access scores.

Revenue decoupling is often paired with EERS. Decoupling mechanisms "decouple" utility revenue from electricity sales by guaranteeing a rate of return established by the PUC. Once implemented, decoupling removes the utility's disincentive to conserve energy.

H5: States with renewable portfolio standards will have *higher* DG access scores.

RPSs mandate utilities generate a certain percentage of electricity from renewable sources. Often, utilities are allowed to achieve compliance from distributed systems, and may even receive compliance multipliers as an incentive to integrate distributed projects.

H6: States with emissions reductions targets will have *higher* DG access scores.

This hypothesis posits that states who have established clear regulatory signals against expanding fossil fuel-fired electric generation will be more favorable to distributed generation. Waning reliance on centrally operated coal power, for example, opens the opportunity for greater generation from distributed renewable energy.

4. *Political & Institutional Factors*[74]

The remaining hypotheses capture the influence of political elements on DG policy. Not only is this project interested in accounting for partisan control, but it also seeks to understand the effect of institutional design, particularly in regulatory commissions. The next set of hypotheses control for partisan composition, which assumes the Democratic Party is more favorable toward renewable energy. The Republican Party tends to favor conventional sources of fuel and is not as quick to support renewable energy through policy or incentives. However, this project seeks to disentangle economic indicators from partisan or ideological factors, so it is essential to include the following hypotheses to control for partisanship:

H7: State legislatures under Democratic control will be associated with *higher* DG scores.

H8: States with Democratic governors will be associated with *higher* DG scores.

5. *Geography*

In addition to the political and economic relationships posited above, I hypothesize that state favorability toward DG access is sensitive to geographical factors. Energy markets are shaped in large degree by resource availability and cost-of-service, and the existing economies-of-scale achieved by fossil fuel fleets will likely impinge upon decision-making that would otherwise favor higher penetrations of renewable energy. While natural gas-fired electricity consumption does not greatly vary by census region, the Midwest, South, and West have higher proportions of the electricity mix sourced from coal than the Northeastern states. This is partially explainable

[74] This project chose to focus on the partisan composition of the institution rather than partisan identification across the states' electorate, because lawmakers and the executive more directly impact the state's policy environment around a complex technical issue such as net metering. Future research can look more closely at the relationship between public attitudes, partisan identification, and DG policy outcomes.

from the higher availability of hydroelectricity in the Northeast, and the West's hydroelectric resources might weaken the effect of path dependence from fossil fuel-fired generation, so I expect the West to have higher DG averages than the Midwest and South.[75]

H9: Regions with higher demand for coal generation (Midwest, South) will be associated with lower DG scores, while regions with lower coal demand and higher hydroelectricity will have higher DG scores (Northeast, Midwest).

Means Comparison Analysis

Now that hypotheses have been laid out, I investigate these relationships by conducting bivariate means comparisons across values of the independent variables. For the independent variables with two categories, I conduct two-tailed t-tests and assume unequal variances for each group. For independent variables with three or more categories, I run one-way analysis of variance using the Bonferroni method to test statistical significance. The results of the bivariate analyses are presented in figure 3.3 below.

[75] Hydroelectricity, like coal, provides baseload generation, or a reliable supply of electricity that constantly provides power throughout all hours of the day (albeit with seasonal and yearly variation). The existence of a baseload source of electricity

Table 3.2 Distributed Generation Score: Intergroup Means-Comparisons

	Mean DG Score	No. Cases
Utility Market Share		
Competitive	19.40*	238
Monopoly	29.43*	28
Duopoly	22.51*	70
Utility Regulation		
Vertically Integrated	17.84*	224
Restructured	26.97*	112
Regulatory Policies		
Energy Efficiency Standards		
No	15.67*	172
Yes	26.34*	164
Revenue Decoupling Mechanism		
No	18.19*	247
Yes	28.37*	89
Emissions Reduction Standards		
No	18.91*	257
Yes	28.20*	58
Renewable Portfolio Standards		
No	14.01*	141
Yes	25.86*	195
Legislative Control		
Democrat	28.47*	93
Republican	16.29*	204
Divided	26.82*	39
Governor		
Democrat	25.36*	121
Republican	18.37*	215
Region		
South	15.63*	112
Northeast	29.24*	63
Midwest	18.37*	84
West	24.44*	77

*Indicates statistical significance at $p > 0.001$.

The difference between means of state DG scores and values across independent variables are statistically significant. In fact, this bivariate analysis allows us to reject the nine null hypotheses outlined in the above section. Some of the relationships tested present interesting, if counterintuitive, results.

Two independent variables were found to have a significant relationship with DG favorability, but in the opposite direction of the one hypothesized. Concentration of utility market share, while apparently revealing only substantially small differences in means, has an *inverse* relationship with DG favorability. The reason for this might be that larger utilities are better equipped to absorb distributed project interconnections than smaller utilities. Intriguingly, the second hypothesis - states that have implemented restructuring/retail choice for electricity markets are associated with higher DG access scores – is supported by the data. States with retail competition *and* large utilities seem to provide the best policy environment for DG access.

Regional variations are statistically significant as well. The South and Midwest have lower scores for DG policy at 16 and 18 points, while the West and Northeast have higher DG policy scores at 24 and 29, respectively. This comports partially with the fact that coal produces a larger proportion of electricity generation in Midwestern and Southern states compared with the Northeast, but it should be noted that the percentage of coal power is roughly equal between the West and South at approximately 34-35 percent, meaning variation in DG policy across regions could be due to something other than coal power. The graph below portrays the difference in density curves for DG scores across regions, highlighting the statistical significance in regional variation of DG policy.

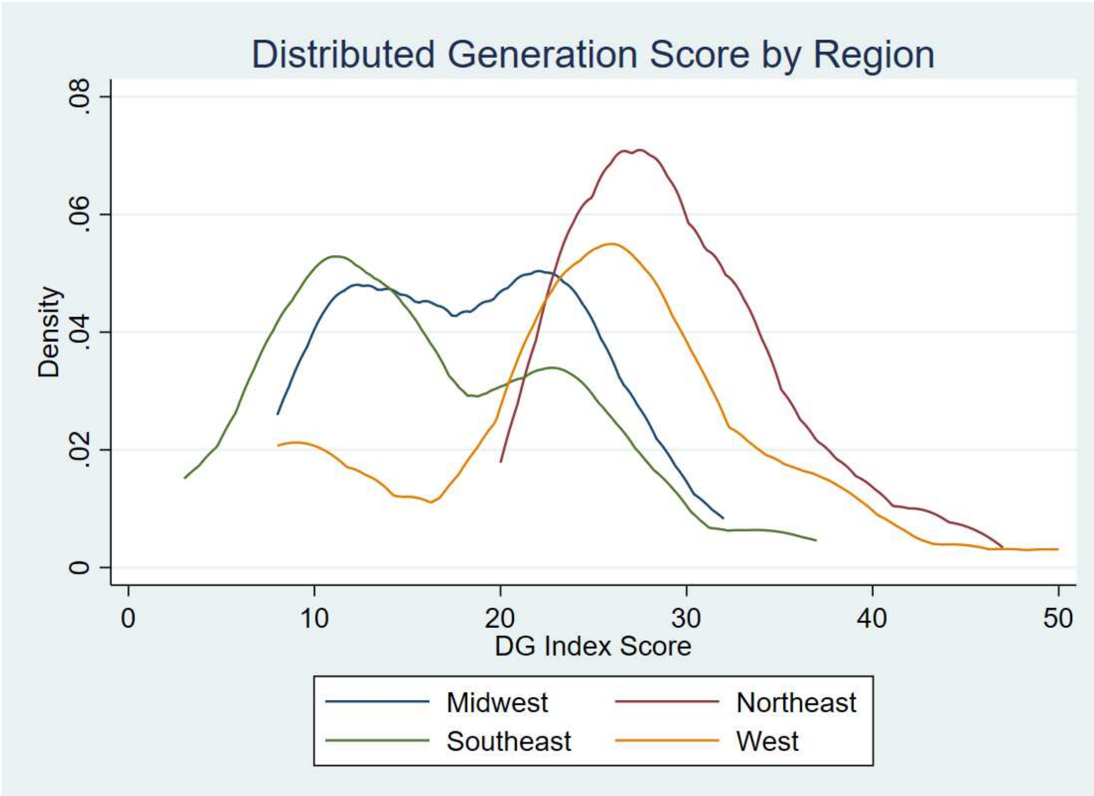

Figure 3.2 DG Score Density Curves by Region

Factor Analysis on Regulatory Policies

Prior to testing the hypothesized relationships in a multivariate model, it will be useful to determine whether the variance in regulatory dummy covariates – RPS, EERS, emissions controls, and decoupling - can be measured and explained as a smaller number of factors. Additionally, it is important to determine whether any one of the four utility policies can significantly explain variation in any or all of the other regulatory policies to address potential issues arising from multicollinearity; the policies might be highly correlated with each other as they all seek to govern utility behavior by mitigating or removing the utility disincentive to reduce power generation. We might expect a state that has adopted one policy to adopt the others. For example, it is plausible that the variance across states in RPS adoption might actually be undergirded by adoption of emissions controls. I conduct an iterated principal factor analysis on the regulatory independent variables to determine whether the set of four regulatory policies are driven by differences in a subset of policies, or whether the regulatory policies can be consolidated into a single scale. If variance in utility regulation is explainable by a single factor, utilizing a scale that measures the construct of "utility regulatory policy" would simplify modeling the posited relationships in a multivariate regression. The results of the factor analysis are presented below in Table 3.3.

Table 3.3 Iterated Principal Factor Analysis on Regulatory Policies

Principal Factors	Eigenvalues	Policy	Factor Loadings
Factor 1	**2.27**	Efficiency Standard	0.76
Factor 2	0.47	Renewable Standard	0.80
Factor 3	0.08	Decoupling	0.70
Factor 4	-0.01	Emissions Standard	0.76
$\chi^2 = 516$; Pr > $\chi^2 = 0.001$			

The factor analysis outputted four factors, and the first factor is emboldened to show that the set of utility regulatory policies can be effectively explained as a single construct. The eigenvalues represent the summed correlations of each policy with each factor. Because the first factor having an eigenvalue of 2.27 and the second, third, and fourth have eigenvalues lower than 0.5, we can confirm that the four policies can be grouped into a single independent variable. The new independent variable – utility regulatory policies – measures the stringency of utility regulation along a single scale. Furthermore, the factor loadings for each of the four regulatory policies are close to equal, ranging only from 0.7 to 0.8, signifying that variation in the utility regulatory environment is not reducible to variation in any one of the policies, despite the fact that there is a relatively high degree of intercorrelation within the four. The result of this analysis allows us to treat utility regulation as a single continuous independent variable when we test the selection of hypotheses together in the multivariate model.

Multivariate Analysis

We now turn to explore path-dependency's influence on DG policy further by incorporating several power sector-relevant economic variables into our analysis. In order to understand the drivers of DG access at the state level, it is necessary to account for certain attributes of energy markets that potentially inform the behavior of electric utilities and their regulators regarding the integration of distributed systems. First, I lay out new hypotheses on the expected relationships between economic indicators of power generation and DG policy. Second, I conduct a multiple regression to test the statistical significance of these indicators and discuss the model's findings.

Economic Factors on Distributed Generation Policy

First, we want to understand the relationship between fossil-fuel fired generation and policy that enables distributed renewable generation. If carbon-based path dependencies constrain policymakers from enabling great access for customer-generators, then we would expect states more dependent upon fossil fuel for electricity to be less proactive in adopting DG access policies.

1. *Proportion of Fossil Fuel Generation in Electricity Mix*

First, I seek to measure the effect of net fossil fuel electricity generation on DG policy. Fossil fuel electricity data is taken from the EIA, which publishes electric industry data monthly and publishes annual adjustments. I collected data on net electricity generation from coal and natural gas, measured in megawatt hours. Because this project hypothesizes *dependency* on fossil fuel sources is a constraint on policy that enables greater DG access, I test the association of the percentage of coal and gas within the state's electricity mix for each year. If path dependency exists, we would expect coal and gas generation to have an inverse relationship with DG score:

H10: States with greater proportions of coal-based power generation will be associated with *lower* DG scores.

H11: States with greater proportions of natural gas-based power generation will be associated with *lower* DG scores

2. *Electricity Prices*

Second, we are interested in determining whether electricity prices exert a significant effect on DG access. Given the concerns over cost-shifting and increasing electricity costs surrounding net metering debates, we might expect that states facing higher electricity prices would be more resistant to further DG integration. Average electricity prices are published by the EIA.

H12: States with higher electricity prices will be associated with *lower* DG scores.

3. *Levelized Cost of Electricity*

The last new relationship takes account of renewable energy costs. Given normal market dynamics, it is plausible that states adopt policies that encourage deployment of DG systems as renewable technology costs fall. Engineering advancements in clean energy might afford a state greater capacity from breaching from fossil-fuel shaped path dependencies. I use a broadly used measure of energy technology costs to examine this relationship: levelized cost of electricity

(LCOE). The LCOE of an energy source is determined by calculating the revenue needed to recover costs for a system's given life cycle.[76] Renewables advocates have used LCOE to illustrate the increasing cost-competitiveness of renewable systems to conventional fossil fuel generation. The calculation will vary greatly on fuel type and scale of deployment; utility-scale projects are generally more cost-efficient than smaller distributed projects. LCOE historical data and projections are compiled by several organizations, but this paper uses Lazard's annual estimates for average LCOE, a reliable source that measures LCOE for multiple renewable sources and differentiates costs between utility-scale and distributed projects.[77] The chapter's final hypothesis is stated below:

H13: Lower LCOEs for renewable technologies are associated with *higher* DG scores.

It must be noted that nationwide estimates for LCOE are far more common and publicly available than more granular estimates for LCOE at the state or local level. Lazard's estimates used in this section are based on US averages. Unfortunately, this prevents the multivariate model from being able to conclusively test the variance in state responses to falling technology costs. Including nationwide averages does have usefulness, however, in controlling for the overall trend downward in renewable costs, helping to isolate the influence of other economic factors on DG policy adoption.

Multivariate Analysis

In order to determine the extent to which the economic indicators of fossil fuel-sourced generation, electricity price, and technology costs affect state DG favorability, I incorporate

[76] EIA 2020. Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2020. Energy Information Administration.
[77] Lazard 2019. Levelized Cost of Energy Analysis - Version 13.0, New York, NY: Lazard Ltd.

these factors in multiple regression model along with the variables examined in the bivariate analysis. Additionally, the factor analysis successfully revealed that variance in the state regulatory policy environment is explainable by a single iterated factor, so testing the regulatory factor against the effect of economic and policy variables will allow us to determine if strong regulatory regimes help states move away from path dependencies shaped by the electricity system. To account for partisan control, I incorporate a variable of the percentage of legislators that are Democratic for each state-year.

Utility market concentration is accounted for by including a variable of the count of utilities with over 25% of the state's market share, displayed in the regression output as "no. large utilities." Because market concentration was positively correlated with DG score in the bivariate analysis, we would expect a relationship in the opposite direction of the original hypothesis in the multivariate model. States with larger utility companies will be associated with higher DG scores, if consistent with the one-way analysis of variance.

While linear regression is a useful method of capturing the marginal effects produced by the proposed factors, results can be problematic if data is not normally distributed. Prior to estimating the regression, I run Shapiro-Wilk tests for normality on the DG index score and coal and gas ratio variables. The Shapiro-Wilk test and the Breusch-Pagan / Cook-Weisberg tests for heteroskedasticity revealed we must reject the assumption that the variables are normally distributed. To make the data amenable to linear regression analysis, I conduct a Box-Cox transformation on the dependent variable of DG scores.

Coal-powered generation is proposed as the primary independent variable of interest, with the utility regulatory environment moderating its relationship with state DG policy favorability. As a general trend, we would expect a high reliance on coal generation to constrain the path of policymakers that might otherwise adopt policy enabling DG access, because higher penetrations of distributed systems would cut into the revenue provided from centrally operated, baseload power plants.

I do not expect natural gas generation to create political resistance to the same degree as coal for two primary reasons. First, while the percentage of natural gas-sourced electricity varies significantly by region like coal power, there is a high prevalence of natural gas generation in the Northeast and a much lower prevalence in the Midwest.[78] Throughout the seven-year period, Northeastern states received 42% from natural gas sources, while Midwestern states received 10%. Western and Southern states ranked in the middle at 25% and 37%, respectively. Referring back to Figure 3.4 in the bivariate analysis, the difference in means of distributed generation policy across regions does not align with the expectation of the hypothesis that higher percentages of fossil fuel generation result in lower DG scores. Northeastern states placed highest in the DG index with an average of 29 points, while Midwestern states averaged significantly lower DG scores at 18 points. This suggests that DG score may not be sensitive to the prominence of natural gas in state electric portfolios. However, an uncontrolled regression of gas ratios on DG scores showed a positive relationship between natural gas and distributed generation access. This bolsters the argument that gas will not exert a path-dependence effect on policymakers to the same degree as coal, but a controlled regression is required to understand whether natural gas proportion has any specific bearing on DG policy.

The second reason is more speculative. Natural gas does not necessarily provide 'baseload' generation, and certain gas projects may be more compatible with renewables than coal. While natural gas combined cycle generators, or NGCCs, comprise a slight majority of gas-

[78] The regional variation of natural gas generation was found by conducting a cell means regression of natural gas ratio by census region.

sourced electricity in the US and are capable of providing reliable baseload power service, other types of gas plants can provide “dispatchable” electricity service. In contrast with baseload generation such as coal or nuclear, dispatchable energy projects can quickly ramp up and taper down electricity generation, allowing grid operators to bring power plants online to meet unexpected or abrupt peaks in demand that arise due to extreme weather events or other exogenous factors.[79] Natural gas “peaker” plants – utilizing either steam or combustion turbines – are equipped to serve spikes in peak demand. The ability for natural gas to facilitate grid adjustments to potentially volatile electricity demand serves in a critical role in balancing the intermittency of renewable energy in the resource mix. In other words, natural gas has flexible applications compatible with renewable systems, the output of which fluctuates based on environmental conditions. When conditions are not suitable for wind or solar energy to serve peak demand, natural gas peakers can fill the gaps in electricity supply more effectively than more inertia-bound energy sources (Jones 2017).

The ratio variables of coal and gas percentages within the electricity mix are similarly distributed, both exemplifying a somewhat high degree of right skewness. I implemented a logarithmic transformation on the proportions of coal and gas electricity generation to address the lack of normal distribution in proportions of fossil fuel sources of energy. To illustrate the relationship between ratio of coal generation and distributed generation policy, I plot the fitted values of the residuals of a basic ordinary least squares regression from the log-transformed coal ratio on DG score in Figure 3.3 below.

[79] EIA 2017. Natural gas generators make up the largest share of overall U.S. generation capacity. Retrieved from: https://www.eia.gov/todayinenergy/detail.php?id=34172

Figure 3.3 displays the expected basic downward trend of the coal-DG policy relationship prior to testing its influence alongside other variables. State-year observations with lower proportions of coal power have DG scores clustered toward the top-left area of the graph, and the DG scores gently slope downward as the ratio of coal-to-total electricity generation increases. Additionally, the dispersal of data points substantially increases as the fitted values line moves to the right with increasing percentages of coal generation. In light of the effects of coal portfolios on DG access portrayed here, we might expect a stronger relationship between coal generation and DG policy in states that have minimal coal generation. Increasing ratios of coal appear to reduce the likelihood that states have adopted robust DG policies, but the statistical significance of this effect reduces substantially when getting into the higher ranges of coal generation.

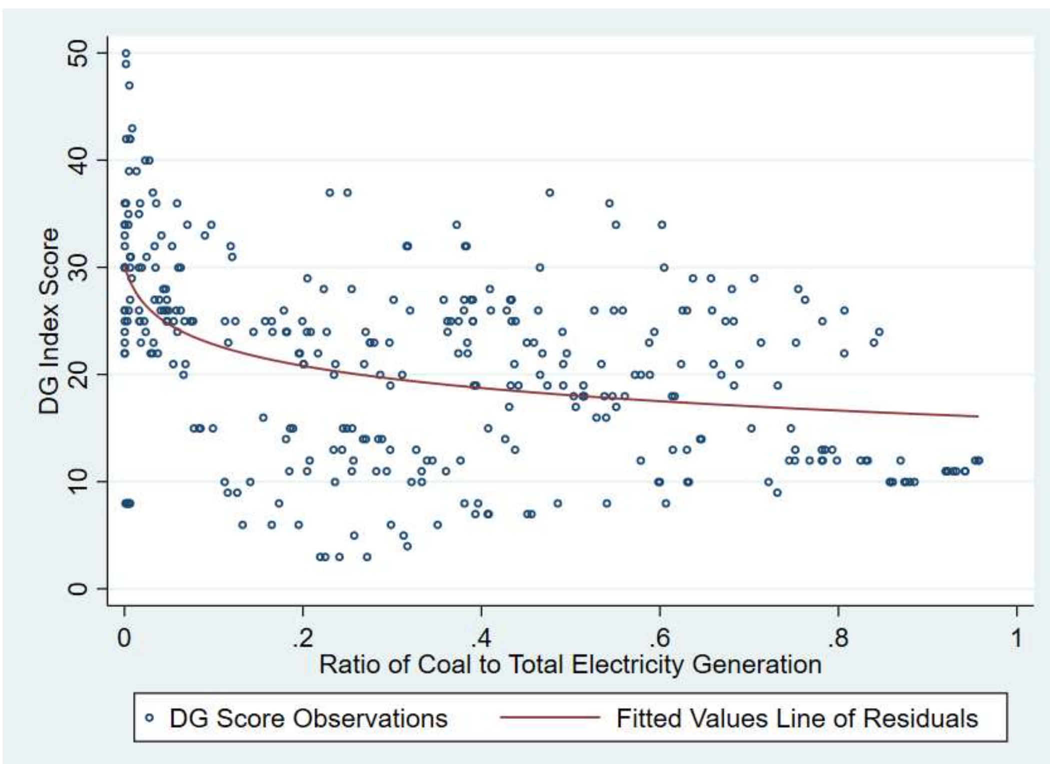

Figure 3.3 Scatterplot, DG Index Scores by Coal-Sourced Electricity Generation

Random Effects Model

Because the dataset is both longitudinal and cross-sectional, measuring policy change in observations throughout years and across states, I treat individual states as panel-level data, using a generalized least squares (GLS) random-effects model to account for residuals from unobserved covariates within states. This is useful because it allows each state to vary across random intercepts, which helps to account for the multitude of characteristics that drive state energy policy not accounted for by the selection of variables tested explicitly. Specifying random effects at panel-level allows us to account for unobserved heterogeneity within states, which mitigates the possibility that apparently statistically significant relationships might actually be driven by omitted variables.

The multivariate analysis requires a careful examination of the influences on state DG access policy. Specifically, I seek to understand how the influence of coal generation is conditioned by the price of electricity, and whether these variables are moderated by regional dynamics. It is also worth investigating if the magnitude of influence is different under vertical utility regulation and retail competition. I first show the output from the GLS regression, then illustrate the moderating effects of electricity prices, region, and electricity restructuring. Presented in Table 3.4 are the results from the random-effects model.

Table 3.4 GLS Random-Effects Model: Influence of Macroeconomic Conditions and Regulatory Environment on Distributed Generation Policy, 2012-2018

Independent Variable	Coefficient	Standard Error	P-value
Macroeconomic Conditions			
Proportion of Coal-Sourced Electricity	3.236	0.695	0.001**
Proportion of Natural Gas-Sourced Electricity	0.184	0.260	0.478
Electricity Price	-0.001	0.267	0.002**
Coal Ratio * Electricity Price	-0.001	0.001	0.001**
Solar LCOE (distributed systems)	-0.001	0.004	0.964
Wind LCOE	-0.070	0.009	0.001**
Regulatory Environment			
No. Large Utilities	1.976	0.791	0.012*
Utility Regulatory Policies	0.867	0.381	0.023*
Electricity Restructuring	2.526	1.037	0.015*
% Legislature - Democrats	0.060	0.014	0.001**
Constant	6.897	4.458	
N states = 48; *N* years = 7; *N* total observations = 336		Wald's $\chi^2(10) = 244.23$, $p < 0.001$;	
Adjusted R^2=0.59; p = 0.861			

Results

The model with chosen economic and regulatory indicators produces an overall good fit at a statistical significance level of p = 0.001. The adjusted R-squared of 0.59 shows that the selected factors explain a substantial portion of the variation in state distributed generation scores. Several hypotheses were found to have statistically significant relationships. The central claim that fossil fuel generation creates stronger path-dependencies, which lowers the likelihood that states will adopt policy enabling greater DG access, appears to be supported by the model, but only for coal-fired generation. The substantive effect of coal on DG score is not straightforward, as the coefficient in this output is positive and significant, which cuts against the hypothesized inverse direction. The true impact of coal generation on DG score is made clear by paying attention to the interaction term of coal and electricity price. In fact, in a separate model that estimated the impact of the log-transformed coal variable absent the interaction with electricity price, the coefficient is negative as hypothesized, but the results were statistically insignificant. A deeper analysis into the effects of coal-sourced electricity on DG policy is needed to paint a more nuanced picture of its influence on DG access, which is found below in the discussion on interaction effects. For now, we can confidently infer that coal power is the greater force in creating carbon-based path dependency than natural gas. The evidence here is not enough to conclude that the ratio of natural gas generation plays a significant role in constraining states from enabling DG access.

The collection of regulatory policies that directly impact utility behavior to incentivize electric providers away from carbon-based sources of energy is also found to be statistically significant. Firmly established regulatory regimes appear to lead states to adopt policies favorable toward distributed generation. Understanding the reasoning behind the role of environmental policies in electricity regulation is straightforward. When a state factors in *environmental risks* deriving from carbon-based electricity generation into utility regulation, the relative value of clean energy and less capital-intensive infrastructure increases. Regulatory constraints that direct energy use toward renewable sources, establish goals of energy conservation, and place limits on carbon emissions reduces the hold of path dependence on the regulatory model by forcing the recognition of environmental risk, in other words by internalizing externalities. Incorporating these public policy objectives into the utility regulatory framework means that utility behavior is not as driven by the financial risks posed by DG integration because the state has structured the regulatory framework with greater certainty.

In line with the bivariate analysis, it is also the case that states with large utilities or duopolies have an easier time enacting DG access policy. The number of large utilities exerts a significant positive relationship on DG score. While counterintuitive to the original hypothesis, the significant result has face validity. States such as New York, California, Rhode Island, Connecticut, and Colorado all have large investor-owned utilities that comprise the vast majority of electricity market share which are directed by state policymakers to implement the state's stringent environmental and energy standards. Midwestern and Southern states such as Nebraska, Oklahoma, Tennessee, and West Virginia, on the other hand, are served in greater proportion by electric cooperatives and municipal utilities.

Not displayed in the regression output above, I separately tested a different measure of utility market concentration by factoring in the percentage of residential customer share of the state's two largest utilities. While the raw number of large utilities does positively influence DG scores, the more precise measure loses statistical significance. This indicates we should be skeptical to conclude that market consolidation neatly results in higher DG favorability. The evidence does give us reason to suspect that in states with more fragmented utility markets – served in larger part by electric cooperatives and municipal utilities rather than investor-owned utilities – might be more hesitant to expand distributed generation. It could be the case that investor-owned utilities are either (a) more resilient to the potential cost-shifting effects of increased distributed generation, or (b) less autonomous due to their need to comply with utility commission rules which might mandate certain DG access programs such as net metering, while cooperatives and municipalities have greater authority to control their resource portfolios, as PUCs have limited jurisdiction over them. Despite these plausible explanations, it is apparent that the degree of variation in market consolidation does not have statistical significance beyond a certain level. These questions will be explored further in Chapter Four within the discussion on PUC decision-making.

While the multivariate analysis presents some evidence for many of the proposed relationships, some hypotheses are not supported by the data. The effects of solar LCOE on DG score is the most peculiar; solar LCOE did not yield a significant relationship, but wind LCOE yielded a statistically significant negative relationship to DG score, in line with the proposed hypothesis. Examining the trend of LCOE within the time period can help explain why the results do not match the expectations of the hypothesis. It is worth noting that solar LCOE and wind LCOE decreased at different rates from 2012 to 2018; average costs of solar decreased gradually per year at a greater rate than wind, especially earlier in the time period. Both technologies, however, experienced steep decreases in costs *earlier* than the interval selected for this study and experienced diminishing marginal decreases for each successive year (Lazard 2019). According to Lazard's estimates, solar and wind LCOE dropped massively from 2009 to 2011, greater than at any point between 2012 and 2018. Expanding the dataset to include earlier years might reveal that these steep cost decreases precipitated policy activity surrounding distributed generation in years shortly after. Furthermore, it should be clarified that the LCOE for distributed photovoltaic solar systems is not only estimated to be higher than for utility-scale systems, but estimates are also more volatile. While the LCOE for distributed solar is estimated to be $177/MWh in 2012 and 2013, it increased to $187/MWh in 2014. Distributed solar LCOE fell over the next two years and rose again in 2017 and 2018. Since this volatility does not coincide with the overall upward trend of DG access scores, we cannot say that lower costs of solar is associated with policy enabling DG access.

Beyond the regression model tested here, there is further reason to suspect LCOE is not a reliable predictor of DG access policy. When testing a separate model that accounts for utility-scale solar LCOE instead of distributed solar, neither wind nor solar costs appear to bear on state scores for DG access. The muddled results of renewable technology costs and the minimal effect of solar LCOE is a product of the nationwide LCOE estimates, and mapping averages for the entire US to state-year means is an imperfect method of determining the impact of energy costs on DG policy adoption. A more granular analysis with location specific LCOE calculations is required to attain a clearer picture of how the trend of falling technology costs affects favorability toward DG integration. Some states are beginning to incorporate locational analysis into planning for and valuation of distributed energy systems to promote the deployment of DG and assist utilities in renewable integration.[80]

Lastly, it is evident that partisan composition significantly affects DG index placement. The model shows states with higher percentages of Democratic control pursue policy more favorable to the expansion of renewable energy, confirming the proposed direction of the hypothesis: states under Democratic control adopt policy enabling DG access to a greater degree than states not under Democratic control. While this is expected, there are interesting facets to the influence of partisan composition on DG policy. First, the index measure does *not* reflect a strong effect from Democratic legislatures if one substitutes a dummy variable for Democratic control rather than an expression of a percentage of statehouse seats. In a separate model, I used a binary measure – whether the legislature was controlled by a Democratic majority – to examine if statistical significance with DG access score held up. Compared to the continuous percentage of party composition, the binary variable did not exhibit the same statistically significant relationship. One explanation is the fact that the Republican Party comprises the majority of state legislatures at 61% within the dataset, and legislatures with divided party control make up another 12% of statehouses, leaving Democrats with majorities in only 28% of observed cases. Democratic control may not have a major effect if DG policies are more likely to be maintained

[80] Gahl et al. 2018. Getting More Granular: How Value of location and Time May Change Compensation for Distributed Energy Resources. Solar Energy Industries Association, January 2018. Retrieved from: https://www.seia.org/sites/default/files/2018-01/SEIA-GridMod-Series-4_2018-Jan-Final_0.pdf

once adopted rather than rolled back by Republican legislation. Interestingly, when testing a separate model by using the Democratic legislative dummy variable rather than the continuous percentage, party control is not found to be statistically significant. While party composition is proposed to be associated with high state DG scores than states under divided or Republican control, the multifactorial model does not reveal significant influence on state DG policy a result of *majority* partisan control of *both* legislative chambers. This might be an optimistic finding for renewable energy advocates; greater Democratic occupancy will result in higher DG scores even if Democrats do not control both legislative chambers. Supermajorities and “blue trifectas” – the term for periods when the Democratic Party controls both chambers and the governor’s office – are apparently unnecessary for pursuing DG access efforts. Simply having more Democratic legislators appears to be effective in advancing DG policy, even if the political conditions are suboptimal.

Interaction Effects: Electricity Price and Geography as Moderator Variables

Using multiple regression is helpful to understand the correlations between economic and regulatory factors within panel data, but because the decision-making surrounding the electricity system is complex, it is important to if the association between a state’s net fossil fuel generation and DG score is sensitive to certain factors. Primarily, we want to test if the price of electricity and geographic region moderates the coal-DG score relationship.

Testing the influence of electricity price on DG access yields unexpected results. *H12* - states with higher electricity prices will be associated with *lower* DG scores – is not supported by the model. However, there is a statistically significant association between electricity prices and DG policy, but we observe the relationship in the opposite direction: states with higher electricity prices are associated with higher DG access scores. There is a potential explanation to make sense of why electricity prices and DG scores exhibits an inverse relationship, which is the fact that there is a major distinction between *electricity rate*, or the retail price of electricity, and *electricity bill,* which is a more accurate reflection of the monthly cost of energy consumption to ratepayers. When comparing state electricity rates to bills, a peculiar discrepancy emerges: regions with lower electricity rates often burden their ratepayers with higher electricity bills. For example, Southern states, despite having lower average electricity rates, often must pay higher electricity bills, while Northeastern states pay lower electricity bills on average despite facing higher energy costs.[81] One reason for this is that states with higher energy costs take further measures to make their power systems more energy efficient to reduce ratepayers' energy burden. Regulators might also develop rate structures more favorable to electricity customers to mitigate energy burdens. On the other hand, states with lower electricity rates tend to have a larger rural rate bases and will typically lag behind more urbanized states in adopting and implementing energy efficiency measures.[82]

Distributed generation systems similarly reduce the energy burden by allowing for ratepayers to offset a portion or all of the costs deriving from their electricity consumption. We might conclude that states with higher electricity rates might also be more likely to establish regulatory environment favorable toward the integration of behind-the-meter renewable systems. This would align with a rejection of the null hypothesis, but with an inverse rather than positive

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[81] Daniel, Joseph, 2019. The Energy Burden: How Bad is it and How to Make it Less Bad. Union of Concerned Scientists. Retrieved from: https://blog.ucsusa.org/joseph-daniel/how-to-make-energy-burden-less-bad

[82] Daniel, Joseph 2018. How Affordable is Your Electricity? Comparing Electric Rates, Bills, and Burden. Union of Concerned Scientists. Retrieved from: https://blog.ucsusa.org/joseph-daniel/state-electricity-affordability-rates-vs-bills-vs-burden

relationship. Further research is needed for clarification on the regulatory process for how states with low rates and high bills approach distributed generation.

Because electricity rates are borne out by geographically determined factors, and states with lower rates appear more reluctant to facilitate DG integration, it is worth exploring whether electricity prices significantly affect the relationship between proportion of coal generation and DG score. The generalized linear model evinced a significant interaction between coal and electricity prices. The predicted marginal effects of the ratio of coal generation on electricity are plotted in Figure 3.4 below.

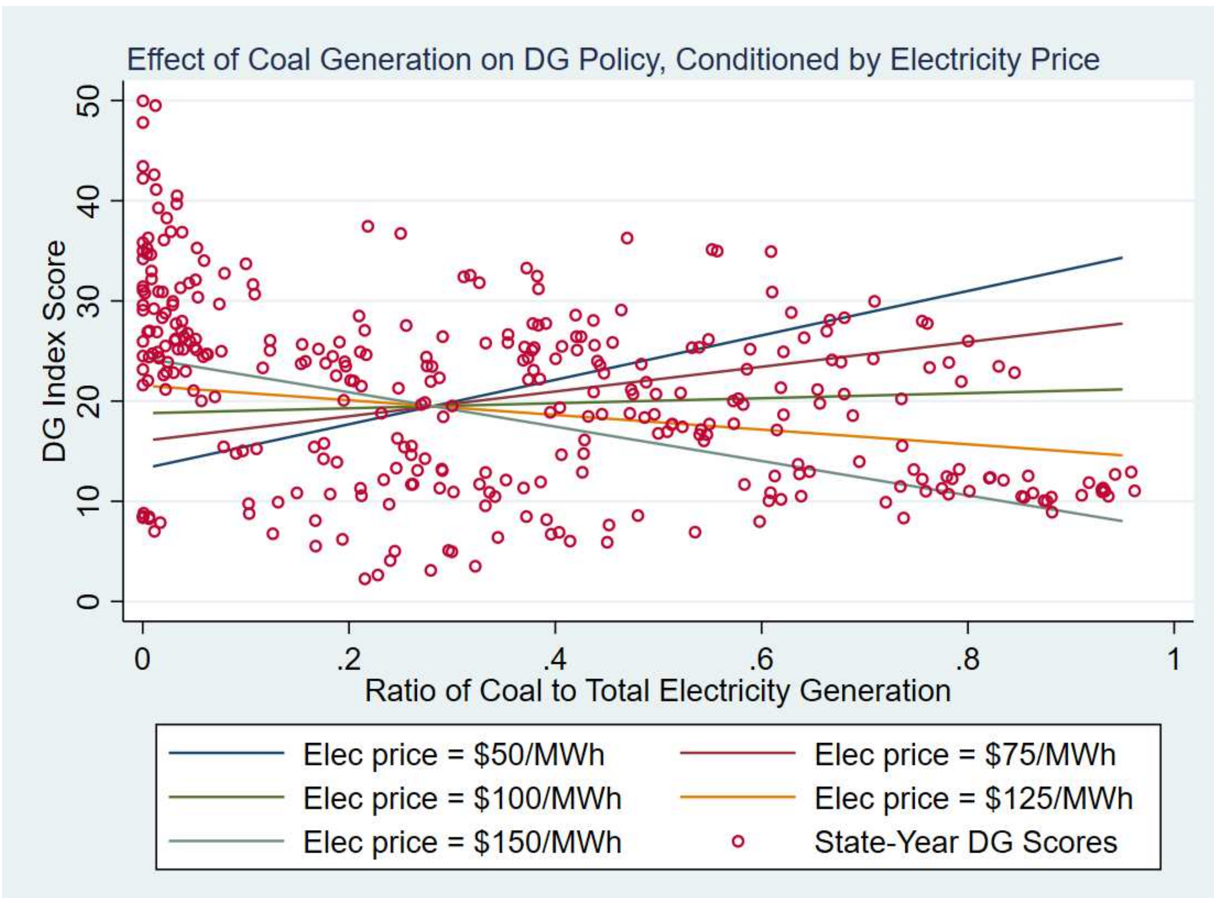

Figure 3.4 Predicted Margins: Coal's Impact on DG Score, Moderated by Electricity Price[83]

[83] \$100/MWh (green line) is the mean price of electricity, with a standard deviation of approximately \$25/MWh. The graph displays the slopes of the effect of coal on distributed generation access at the mean and +/- two standard deviations.

When accounting for interaction effects, electricity price is revealed to be a significant moderator of the coal-DG relationship. Remember that electricity prices are equivalent to electricity rates and do not necessarily reflect higher electricity bills. As the average price of electricity *increases*, the impact of net coal generation aligns more closely with the expected inverse relationship of coal generation on distributed generation policy. For example, the light blue line represents the electricity price of $150/megawatt hour (MWh), which is two standard deviations above the mean electricity price of $100/MWh. For states whose electricity rates are closer to $150/MWh, their likelihood of adopting DG access policies reduces as proportion of coal-sourced generation increases. The impact of coal generation on DG score is relatively flat toward the mean. As the price of electricity *decreases*, and a state experiences lower electricity rates such as $50/MWh, the coal-DG relationship is positive, and a state would be expected to have a lower DG score if they have a lower percentage of coal-sourced electricity.

What might explain this interaction between ratio of coal generation and electricity, and why would states appear to be more favorable toward DG access as the ratio of coal generation increases? It is possible that regional interactions must also be accounted for. For example, coal-heavy states in the Midwest such as Ohio and Michigan, some Northeastern states such as Pennsylvania, and Western states such as New Mexico, Utah, and Montana all have fairly high percentages of coal-fired electricity, but all have DG index scores close to or above the mean of 21 points. These states are not as dependent on natural gas generation as Southern states, which have lower electricity rates, but higher bills. The lower cost of electricity across many parts of the South, Midwest, and Western regions, combined with the high presence of coal in several states that have adopted robust DG policy, confounds any direct bearing of coal generation on DG policy. The evidence presents the possibility that higher electricity prices force states to adopt DG policies in hopes of lowering the energy burden for their ratepayers, but reliance on coal-sourced generation constrains decision-making. States with lower electricity rates may be more reluctant to adopt DG access in fears that rates will increase as a result, but that resistance appears less present in states that are more dependent upon coal generation.

To unpack these moderating relationships further, I test an interaction of coal-DG with geographical region in hopes of clarifying the differences in coal's impact on DG policy in states with varying environmental and economic attributes. Moreover, I set the coal-region interaction as conditional upon the type of utility regulation, separating the states into two groups: vertically integrated states, and states with restructured electricity markets. This exercise allows us to visualize the impact of the "restructuring" dummy variable on DG scores while understanding how the regulatory structure conditions the effect of coal generation on DG access. To restate the hypothesis regarding electricity restructuring, we expect restructured states to be more facilitative of DG access, because increased market competition means ratepayers have greater range of choice in selecting their electricity providers. Retail competition means that utilities do not have a stranglehold on customers' sources of energy and customers are not necessarily locked into to receiving energy from centrally operated utility power plants. Figure 9 below portrays the coal-DG relationship, conditional upon restructured vs. integrated regulation. The slopes for the four census regions are plotted out separately to highlight the differential marginal effects in each.

Regional and restructuring moderating effects are evident in the marginal effects graph. The ratio of coal does bear as greatly upon DG scores in vertically integrated states as restructured states. This is expected; if retail choice allows customers great ability to discriminate their energy sources, it would follow that these states would enable greater access to interconnect to the distribution system. Not only is the relationship much weaker in vertically integrated states, but one region, the Midwest, shows a positive relationship between coal ratio and DG score. Coal-heavy Midwestern states also tend to have high proportions of wind-sourced electricity. It may be the case that Midwestern states have attempted to expand the renewable market due to the high wind potential in the region. Southern and Western vertically integrated states exhibit roughly the same relationship: for every unit increase of coal in the electricity portfolio, the DG index score decreases.

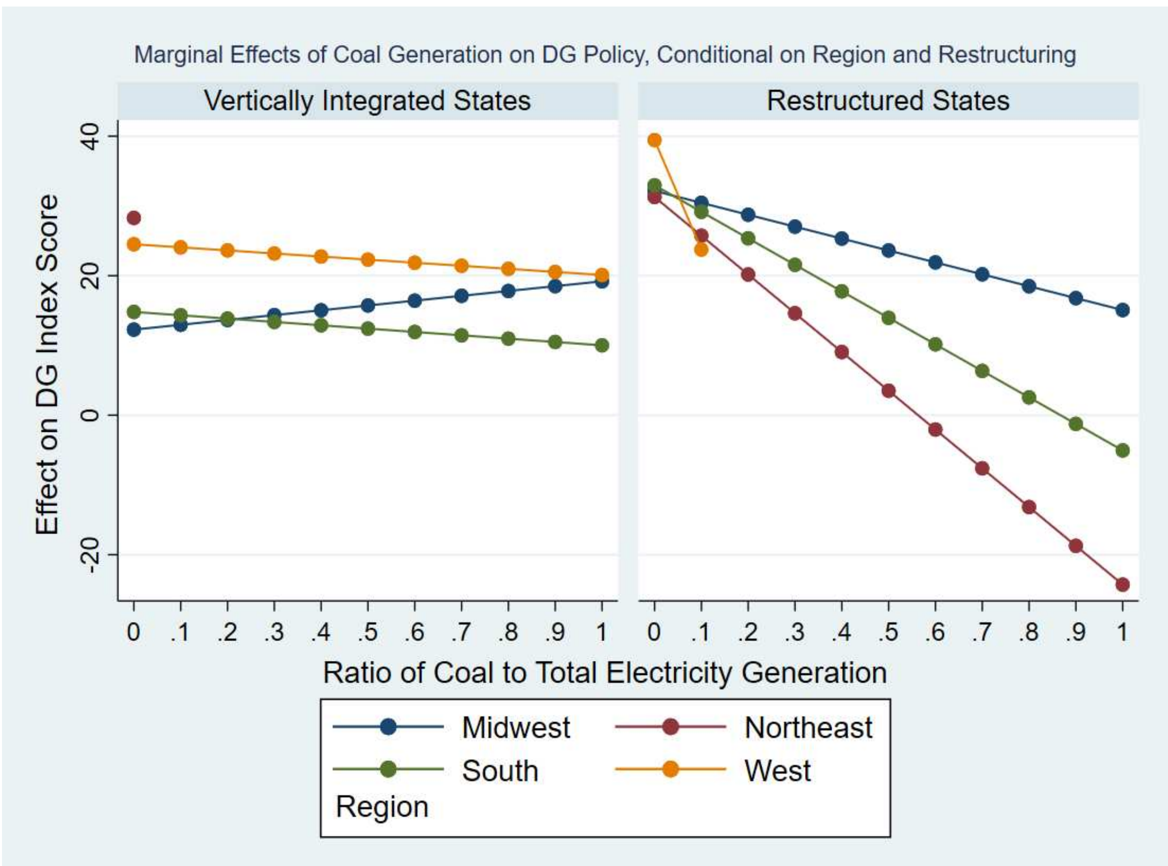

Figure 3.5 Coal's Impact on DG Score, Conditional Upon by Restructuring and Region[84]

[84] Most Northeastern states have restructured electricity markets, hence the singular data point in the 'vertically integrated' box. Vermont is the only vertically integrated state in the Northeast. Only Oregon has restructured status in the West (California has rolled back restructuring status).

The regional interactions are more pronounced in restructured states. All slopes align with the expected direction of the hypothesis, but the effect of coal ratios on DG access is more prominent in some regions than others. The Midwestern region shows the least substantial influence from coal ratios, which comports with the counterintuitive findings for vertically integrated Midwestern states. The South exhibits a greater inverse relationship between proportion of coal and DG score, exemplified by the exceptionally coal-heavy states West Virginia and Kentucky, which skirt the bottom of DG scores across state-year observations. In the Northeast, coal ratio appears to bear greatly on DG score, but it must be noted that Northeastern states by-and-large are not reliant on coal to a great degree; the region's average coal generation comprises a paltry 6% of the electricity portfolio. Because of this, we lose statistical significance as we move right along the Northeastern slope in the graph, and confidence intervals dramatically increase. Nonetheless, we can infer that the region's low coal ratios and high DG scores aligns with the hypothesis about coal's impact on distributed generation access.

Conclusion

This chapter first sought to measure distributed generation access via an index measure that accounts for a range of policies that enable the integration of distributed systems. Of particular importance are statewide interconnection standards and net metering programs, otherwise called distributed generation compensation policies. Then, the chapter tested whether DG scores differ significantly across region, regulatory frameworks, and economic conditions. Once we determined that the regulatory environment could be measured as a scale of regulatory stringency, we tested hypotheses to capture whether the variation in DG scores across state-years can be explained by path-dependency, which is shaped by macroeconomic conditions such as fuel sources and electricity prices, and the nature of the electricity market. The table below summarizes the hypotheses testes and their results.[85]

Table 3.5 Summary of Quantitative Results (Policy Index)

Independent Variable	Hypothesis	Result
Coal generation	States with greater proportions of coal-based power generation will be associated with *lower* DG scores.	Reject null*
Natural gas generation	States with greater proportions of natural gas-based power generation will be associated with *lower* DG scores	Fail to reject
Electricity Price	States with higher electricity prices will be associated with *lower* DG scores.	Reject null*
Solar LCOE	Lower LCOEs for solar technologies are associated with *higher* DG scores.	Fail to reject
Wind LCOE	Lower LCOEs for wind technologies are associated with *higher* DG scores.	Reject null
Utility market concentration	States with greater utility market concentration will have *lower* DG access scores	Reject null**
Regulatory policies scale	States with energy and environmental regulations are associated with *higher* DG access scores.	Reject null
Restructured market	States that have implemented restructuring/retail choice for electricity markets are associated with *higher* DG access scores	Reject null
Partisan legislative control	State legislatures under Democratic control will be associated with *higher* DG scores.	Reject null

* Impact of coal on DG access score is conditional on electricity price (see Figure 8)
**Utility market concentration has the *opposite* effect on DG score than the stated hypothesis.

Primarily, the analysis concluded that higher proportions of coal-sourced electricity generation is correlated with lower DG scores, but this relationship is conditioned significantly by region and by electricity price. Coal appears to exert a more prominent path-dependency effect in states that have restructured electricity regulation, and Midwestern states are impacted minimally, if at all, by the proportion of coal generation. Moreover, states with higher utility market concentration appear to constrain states *less* in adopting DG access policies. States that are served by larger

[85] See Chapter Five for an in-depth discussion and further analyses of the results.

utility companies tend to have higher DG scores. Yet simultaneously, states with retail electric competition *also* are associated with higher DG scores. On the surface, the case would be that states with restructured markets *and* large utilities result in higher scores on the DG index. Conversely, states with fragmented market share are associated with lower DG scores.

Our most immediate and confident conclusion from the results is that path dependence based on fossil fuel generation and the utility market structure exert some constraint on the regulatory environment for DG access. The conditional relationships surveyed above showed that neither coal power nor electric centralization impinge upon DG integration in a direct way. Further, we are unable to neatly account for policy drift and whether that concept characterizes DG policy, but the analysis regulatory decisions in the next chapter is better equipped to ascertain the degree of drift.

These observations give rise to several questions. Why is it that large utilities seem to effect change in favor of distributed systems? Why is it the case that regions with lower electricity prices and higher percentages of coal generation tend to increase DG access, which is counterintuitive with our analysis and seems to undercut the theory of fossil fuel-based path-dependency? The outcome could be a case of regulatory capture – in which utility corporations seek to adopt DG programs through the regulatory process to facilitate DG integration but while maintaining market control. If this explanation were true, it would allow utilities to avert the risks of DG deployment and act as the "gatekeepers" of distributed generation, facilitating some degree of customer-driven adoption of renewable systems whilst protecting their centrally operated generation assets. In order to tease out the dynamics between utility regulatory frameworks and distributed generation access, and in order to further explain the interactions of electricity prices and region, this project will now turn to examine the regulatory process surrounding distributed generation policy. The next chapter analyzes the factors that influence the decision-making process of public utility commissions.

Chapter IV

Public Utility Commissions and Regulating Distributed Generation

Introduction

The previous chapter explored the influence of macroeconomic conditions and regulatory factors on state-level distributed generation (DG) policies, emphasizing the role of fossil fuel-based generation and utility market concentration in creating path dependencies that constrain policymakers in enabling greater grid access for DG systems. The chapter found that, while states heavily reliant on coal for electricity generation are less likely to adopt policies more favorable for DG access, this is not a trend in all observed cases. States with high electricity rates tend to be more constrained by the proportion of coal generation in their resource portfolios; alternatively, states with lower electricity prices do not appear to be significantly constrained by coal capacity, and even a positive relationship is revealed between ratio of coal generation and distributed generation index score. When examining states' resource portfolios in the low-end of the range of electricity prices, it becomes clear that, despite the prevalence of coal power across the South, Midwest, and Western states, many states within these regions with lower energy costs have higher levels of natural gas generation relative to coal. Natural gas generation was found to not have any significant association with DG index score, though it is hypothetically plausible that states more reliant on natural gas would be less resistant toward integrating distributed renewables, since dispatchable natural gas can more easily fill the gaps in intermittent renewable generation than centrally operated coal power. More empirical evidence is needed to confirm that natural gas reduces political resistance toward renewable energy. The analysis does show that having a robust environmental regulatory regime that structures utility behavior is associated with higher DG scores, suggesting that path-dependency can be weakened with an articulation of clear public policy objectives that adequately values carbon-free electricity and devalues utility sales based on volume sold.

While the state-level analysis using an additive index to measure DG policy is illustrative of the general trends and relationships at work on a large scale, this chapter seeks a deeper examination of the political and economic factors that influence DG access within the policymaking process. As discussed in chapters one and two, efforts to enable DG access or introduce environmental objectives into the power sector are sometimes thwarted at the regulatory phase. The state's Public Utility Commission, or PUC, is tasked with regulating electricity corporations and ensuring they meet three primary objectives: 1) safety, 2) reliability, and 3) affordable service to ratepayers. PUCs are also charged with implementing policy changes adopted by the state legislature, and state lawmakers might determine that is in the public interest to increase renewable energy or reduce greenhouse gas emissions from power plants. The PUC must then implement statutory directives, but new policy goals might clash with the PUC's long-standing jurisdictional charge. Because PUCs must adhere to the three objectives which have historically directed their decision making, other policy objectives, such as increasing DG deployment, might lose priority in regulatory decision making if they conflict with the reliability and affordability of electricity service.

To recall the discussion in earlier chapters, the construct of cost-of-service rate regulation is interdependent with the three conventional PUC objectives of reliability, affordability, and safety. The natural monopoly of utility infrastructure has created the scenario in which large investor-owned utilities provide the majority of power to US citizens, so any systemic changes that disrupt utility revenue would, by extension, impact ratepayer bills. Hence, high levels of DG penetration on the electricity grid means that revenue that would be produced from centrally owned power plants gradually is reduced with growing levels of distributed generation, which allows customers to offset their electricity consumption and avoid paying into infrastructure costs. On a grid with high DG deployment, utility assets comprise a diminished proportion of kilowatt hours (kWh) sold, and the utility must look to recover capital investments by raising fixed costs on non-DG customer bills.[86] It has been argued that this amounts to "cross-subsidization" or "cost-shifting," since non-DG customers would be paying for electricity infrastructure that DG customers utilize via interconnection, but do not pay for, since they can provide their own electricity on-site.

Because of the changing utility system and policy environment across the US, which is shifting toward a system powered in larger proportion by distributed systems, the PUC is situated as the fulcrum for DG access debates. Utility regulators must balance their historical charge with new policy objectives to facilitate system-wide changes for power generation. In this role with conflicting values, some PUCs may favor greater DG access, while others are more resistant to DG access due to their potential to cause disruptions for electric utilities and ratepayers. By focusing on the regulatory phase of the policy process, this chapter poses the research question: *why do PUCs vary in their favorability toward increased DG access?* Alternatively: *what causes PUCs to incorporate environmental/pro-DG objectives in their decision-making?* To answer these questions, this chapter conducts a quantitative analysis of the political and economic factors associated with PUC decisions regarding distributed generation, seeking evidence that PUCs are path-dependent, explainable in part due to *regulatory drift*.

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[86] Edison Electric Institute, 2013. A Policy Framework for Designing Distributed Generation Tariffs: https://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/EEI%20-%20A%20Policy%20Framework%20for%20Designing%20Distributed%20Generation%20Tariffs.pdf

Regulatory Drift and Distributed Generation Policy

This section describes the theoretical basis for investigating PUC decision-making as a function of regulatory and economic path dependencies. The concept of regulatory drift is a useful concept in political science and institutional public policy literature to aid our understanding of the different drivers of policy change across governmental branches, and whether policy change proceeds at different rates within different entities. Regulatory drift can manifest at multiple levels of government in a federalist system, in which subnational governments fail to implement the objectives set in the national legislature (Carter et al. 2017, Ozmy and Jerell 2012). This project seeks evidence of bureaucratic drift at the state level, in which the administrative apparatus is slow to satisfy the policy objectives established in state legislatures (McCubbins, Noll, and Weingast 1987; Macey 1992; Epstein and O'Halloran 1994; Eisner 2017).[87] Drift can also be a product of policy incoherence, when policy mixes contain inherently contradictory objectives involving diametrically opposed interests (Howlett et al. 2009). *Coalitional drift*, in which organized interests and stakeholders develop regulatory policy to protect established flows of economic returns rather than alter the status quo, could be the primary cause of administrative resistance to paradigmatic policy change (Epstein and O'Halloran 1994; Shapiro and Guston 2006). Turning to the electricity sector, the conflictual flashpoints that arise out of environmental protection or innovative technology policy are evident; the economic returns to public utilities face new risks if the industry must comply with fossil fuel-reductions or asset retirements. For this project, "regulatory drift" would be signified by PUCs stymying, delaying, or rolling back

[87] It must be noted that policy drift can occur in either direction; either as a retrenchment against new policy regimes *or* as an avenue of policy making absent statutory directives. Riccucci (2018) discusses how administrative and subnational institutions advanced climate policy despite lack of federal action in *Policy Drift: Shared Powers and the Making of U.S. Law and Policy*. However, this dissertation is focused on regulatory drift that conflicts with and drifts regressively from statutory goals. See Chapter 2 for further discussion.

renewable energy policies that would create systemic changes across the utility system, including threats to ownership over electricity infrastructure.

An analysis of PUC decisions allows us to examine the factors that stymie efforts to enable DG access. The regulatory charge of PUCs to maintain system reliability and affordability allows us to test the theory of path-dependency more acutely, as PUCs have greater information and technical expertise than state legislators.[88] Moreover, the PUC process involves a great deal of coordination between commission staff and utility companies, raising the question of regulatory capture by electric utilities (Gormley 1983). By the same token, PUCs are repeatedly a source of frustration for renewable energy advocates, as some decisions engender the perception that PUCs are responsive to utility needs at the expense of renewables or DG access (Stokes 2016). The close-knit policy network among regulators and regulated industries is the natural result of the evolution of the regulatory compact and utility business model, as preserving the profit mechanism for electric power companies to continue investments is part of the PUC's regulatory charge. This chapter will explore two general prongs that might provide evidence of path-dependency in PUC decision-making created from regulatory drift, which is driven by two market factors.

First, I examine the extent to which resource portfolios and electricity markets create path-dependencies in regulatory decisions. The analysis of energy portfolios in chapter three suggested that a straightforward relationship between resource type and grid access favorability is improbable, and the effect of operating generation sources on adopted policy objectives is conditional upon geographic region. DG policies follow regional trends as they are affected by

[88] National Association of Regulatory Utility Commissioners, 2007. Information Sharing Practices in Regulated Critical Infrastructure States: Analysis and Recommendations. https://pubs.naruc.org/pub.cfm?id=536E206C-2354-D714-515A-81819AA70A02

coal-fired generation conditional on geography, and states with deregulated or restructured electricity markets tend to feel the constraining effects of a coal-heavy generation mix more prominently than vertically integrated or traditionally regulated states. Fostering market competition appears to provide a more favorable environment for distributed generation, because electricity customers have greater choice in electricity provider than in traditionally regulated, vertically integrated states. These findings comport with the expectation that conventional rate-regulation creates stronger path-dependencies, since greater levels of distributed generation systems can result in lower utility revenue and create cross-subsidization or cost-shifting in the utility rate base. These states appear to be less responsive to changing external conditions, such as lower technology costs for renewable energy. This chapter seeks to answer whether regulatory decisions are responsive to energy market characteristics to the same degree as statutory decisions. If path dependence shapes PUC decisions to a greater degree than state-level policy, this might serve as evidence of regulatory drift; PUCs could be opting out of potential actions to increase distribution system access in order to maintain the prevailing business model that sustains utilities from volumetric sales. Regulatory drift is observable when PUC decisions favor a status quo-approach by rejecting or neglecting to adopt policy changes that (a) potentially threaten utility revenue or result in cost-shifting to non-DG customers, or (b) would align would statutory policy objectives of increased deployment or renewable or distributed energy.

Second, this chapter seeks to determine whether utility market concentration influences DG policy at PUCs. Not all significant results from the state-level analysis aligned with the expected tendency. Perhaps the most noteworthy finding of chapter three is that, despite the fact that retail competition states are a more favorable political environment for distributed generation, states with greater utility market concentration are more likely to have adopted policies favoring greater DG access. States with larger utilities rate higher on the DG index, while states with fewer large utilities rate lower on the index. If we accept that PUCs are closely engaged with utilities in the regulatory process, this is a counter-intuitive finding; we might expect large utilities with well-funded staffs and greater resources to exert greater pressure on PUCs and enjoy higher probabilities of success in policy outputs. Nevertheless, more concentrated markets appear more favorable toward distributed generation, but further analyses are required to untangle the true relationships at work.

What factors makes this possible? I contend that, since PUCs are the locus of power system regulation, commission decisions are heavily informed by economic, financial, and technical analyses. Grid *capacity* might play a significant role in a PUC's decision to enable DG access, and distribution system hosting capacity is in greater supply in the service territories of large investor-owned utilities. Conversely, states with smaller, fragmented electricity markets have less capacity to integrate distributed systems and run higher risks of cost-shifting. This chapter will tease out these relationships by including variables on power system characteristics in the analysis of PUC decisions.

Beyond the methods to measure and test the impact of path dependence outlined above, this chapter explores how elements of institutional design can create path dependencies or cause regulatory drift. Specifically, the project explores whether commissioner selection, term limits, and bipartisan requirements affect the PUC's disposition toward distributed generation, and whether these structural elements result in alignment with wider state policy objectives. Capturing the effects of these political variables in the analysis will illustrate the intergovernmental picture of utility regulation more clearly and allows us to discern if principal-agent problems are the cause of regulatory drift in DG policy.

Measuring PUC Decisions on Distributed Generation Access

In order to gain a clearer picture of how distributed generation access is approached at the regulatory phase and which factors bear on decision-making, it is necessary to isolate regulatory outcomes from state-level policy outcomes by examining PUC rulings themselves. This section first describes the data to measure PUC dispositions toward DG integration, then provides a general description of PUC behavior across states within the 2012-2018 timeframe.

Dependent Variable: PUC Decisions

The data for the dependent variable consists of PUC rulings that affect distributed generation access. Documents containing documentation of commission rulings are publicly available and published on state regulatory agency websites. This project defines "access" broadly; decisions that affect compensation rates, meter aggregation regulations, system capacity limitations, interconnection standards, and other rulings that potentially impact DG access or adoption were collected from published PUC dockets. This project is not explicitly studying commission-initiated investigations, rules reviews, or other PUC actions that do not directly result in policy outputs bearing upon distributed generation customers. Only rulings that substantially alter regulations affecting DG access are coded in the dataset.

In addition to policy decisions that modify the components of net metering and interconnection rules explored in the previous chapter, this chapter studies policy changes that are smaller in scope but still pose ramifications for DG system uptake. For example, policies regarding DG that affect a utility's compliance with environmental regulations are accounted for, and PUC decisions that allow net metered renewable systems to count toward a utility's compliance for a state's renewable portfolio standard would count as a decision positive for DG access, because it drives the utility to encourage DG adoption amongst its customer base. By examining regulatory decisions that impact governance across a utility's service territory, we are also taking account of policies impactful at the utility-level or program-level of analysis. This is justified because the typical IOU franchise encompass large swaths of state populations. PUCs will often affect distributed renewables in the context of utility rate cases, such as by modifying the rate design or how distributed systems are valuated in avoided cost methodologies. These decisions may not influence DG regulations statewide, but they still represent significant policy change for the population served by the utility, particularly if the provider is a major investor-owned corporation.

While this study seeks to explore decision making at the state and program-level units of analyses, this chapter does not use the same systematic treatment for *project*-level PUC decisions. PUCs are tasked with approving, rejecting, and providing recommendations for utility resource plans. Electricity generation facilities of a certain minimum size must be reviewed by regulators to ensure that the project will not impinge upon power system operations or result in unreasonable rate increases for utility customers. The PUC may determine that more intensive reviews are required for projects that greatly affect the distribution system. An analysis of distributed renewable energy project approvals and rejections by the PUC would provide a deeper understanding of commissions' orientation toward distributed energy integration, particularly in the ways that PUCs promote or discourage utility investment in technologies with potential to transform the electricity grid toward one that is powered in increasing proportions from distributed generation. Nonetheless, the chapter focuses on more encompassing rulemakings and program-related decisions and leaves the question of project-level decision making for future research. It should be noted that certain utility initiatives, such as community solar programs, might be tied to shared renewable generation projects, but these programs are included in the analysis because the benefits are often made available to a wider segment of the utility's customer base. Decisions related to distribution systems projects are coded if they mark an effort to implement DG access expansion, but proceedings opened to grant or reject certificates of public convenience or necessity (CPCN) to site new facilities are not included. More granular analysis of siting and permitting decisions will be left for future study. The approval of pilot programs that include demonstration projects are also coded if the projects are intended to advance distribution system transformation or provide customer greater access to the distribution grid.

Also excluded from the analysis are decisions that might *indirectly* affect DG deployment through the influence of utility behavior through rate design changes. Administrative reorganization or modifications to budgeting processes are also excluded. For example, if an electric company is seeking adjustments to their revenue requirement to accurately reflect the cost of administering a renewable energy incentive program, this decision is not coded, but if the utility is seeking PUC approval for a renewables program or an expansion of an existing program, these decisions are included in the data set. Decisions based around long-term resource plans are included if they are explicitly tied to expansion of DG access. While utility ratemaking is not the focus of this project, rate design modifications that would directly impact the adoption of DG technology are included. Some commissions have actively worked to facilitate the integration of DG by opening proceedings intended to define the value of distributed energy resources (DER) in utility planning.[89] These proceedings often seek to determine methodologies for quantifying the benefits DERs provide to the electricity grid and ratepayers.

Additionally, some PUCs have sought to determine the value of DERs toward advancing state environmental objectives. California, for example, instituted a "Greenhouse Gas Adder" into the avoided cost formula that informs utility resource decisions, effectively pricing carbon externalities.[90] Several states have mandated that utilities consider the social cost of carbon into their integrated resource plans.[91] Since the addition of distributed renewable energy to the electricity mix defers or eliminates the need for potentially more carbon-intensive infrastructure such as transmission or generation facilities, a utility would be driven to deploy greater DERs if carbon externalities were priced into ratemaking calculations. Incorporating these types of decisions also allows to determine the degree to which PUCs are aligned with their state's environmental objectives. Emissions reductions benchmarks are not included, since utilities could feasibly meet them through changes to their large-scale generation portfolio.

To determine the degree of DG favorability across PUCs, I use an ordinal coding methodology, categorizing decisions using an unordered scheme within a four-point range of values from zero to three. The four-point coding is scale is more useful in this context of regulatory decision making than a binary coding scheme, because decisions are often not wholly beneficial to one party and disadvantageous to another party in public utility proceedings. Decisions to adopt or amend DG rules are often reached through settlement agreements, with stipulations formed as a product of compromise between electric corporations and renewable

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[89] National Association of Regulatory Utility Commissioners, 2019. The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198
[90] California PUC Rulemaking R-14-10-003, Decision 17-08-002.
[91] 'States Using the SCC,' Institute for Policy Integrity, New York University School of Law. Retrieved from: https://costofcarbon.org/states

energy developers. Rulings coded “0” indicate the least favorable outcome for distributed generation, indicating major program rollbacks or restrictions for DG access. Decisions coded “1” reflect a general adherence to the status quo, but also includes compromise decisions in which, in general, might include actions that stymie efforts to enable DG access, but do not entirely dismantle existing DG programs. “2” decisions are positive regulatory outcomes for DG access but may include stipulations such as increased interconnection fees or variable customer charges. Decisions coded “3” are the most positive for DG access and can either include regulations that significantly expand DG access, such as the adoption of a new program to meet the public policy objective of increased DG deployment, or decisions that reject proposals for new restrictions on the distribution systems. Table 4.1 below contains the coding scheme for PUC decisions related to distributed generation.

Table 4.1 Ordinal Coding Scheme for PUC decisions

Code Value	Description	Example
0	DG program rollbacks; new restrictions	Ohio PUC’s reduction of net metering compensation from the unbundled energy rate to energy-only rate[92]
1	Neutral/status quo/compromise decisions; maintaining DG programs with imposed charges	Louisiana PSC’s removal of the aggregate cap and reduction of net metering compensation to the avoided cost rate[93]
2	Favorable for DG access with stipulations; approval of utility programs	Colorado PUC’s approval of Xcel Energy’s community solar program[94]
3	Rules that mark regulatory shift toward DG-oriented electricity system; rejection of new utility restrictions	New York PSC’s adoption of the Value of Distributed Energy Resources (VDER) tariff[95]

[92] Public Utilities Commission of Ohio, Docket 12-2050-EL-ORD, 8 November 2018.
[93] Louisiana Public Service Commission, Docket R-33929, 17 November 2016.
[94] Colorado Public Utilities Commission, Docket 16A-0055E, 23 November 2016.
[95] New York Public Service Commission, Docket 15-E-0751, 14 September 2017.

Descriptive Analysis

After coding all major distributed generation-related PUC rulings on the four-point scale, the complete dataset consists of a total *n* of 228 observed cases. Not all of the 48 contiguous states had major decisions surrounding distributed generation; five of the 48 states were dropped from the analysis due to lack of data. Most of the states are predominantly rural and characterized by absence of activity on distributed generation and renewable energy in general, so the lack of regulatory changes in the DG arena is unsurprising. Three of the states – Nebraska, South Dakota, and North Dakota – are all located in the West North Central census subregion and do not have statewide compensation schemes for excess electricity generation. West Virginia, the fourth excluded state, was a late adopter of net metering and did not adopt any major decisions within the 2012-2018 timeframe. Delaware is the fifth state to not have any major rulemakings, and it is worth noting that a single investor-owned utility (IOU), Delmarva Power, serves over three-quarters of the state.[96]

The frequency distribution across the coding scale reveals a distinct trend: major PUC decisions, within the contours of this study's design, appear to have favored DG access much more often than not between 2012 and 2018. While this dissertation has suggested that PUCs might be more hesitant than legislators to adopt policies beneficial for DG integration, the data shows that PUCs have reliably, if gradually, decided to enable DG access for the majority of cases in this sample. Roughly 21% of the dataset could be hypothesized as instances regulatory drift, as only eight percent of the 228 decisions accounted for can be categorized as outright program rollbacks or rejections, while 12.3% are categorized as neutral/compromise decisions,

[96] EIA-861, 2012-2018.

or slightly less favorable for distributed generation. The remaining 79% of cases are either somewhat favorable or very favorable for the expansion of DG access. Table 4.2 and Figure 4.1 below illustrate the frequency distribution of the coding scale.

Table 4.2 PUC Distributed Generation Access Scale, Frequency Distribution

PUC Decision Code	Frequency	Percentage	Cumulative %
Rollback/Restriction (0)	19	8.33	8.33
Neutral/Compromise (1)	28	12.28	20.61
DG Program Approval/Expansion (2)	84	36.84	57.46
Major DG Policy Adoption/Rejection of Restrictions (3)	97	42.54	100
Total	228	100	

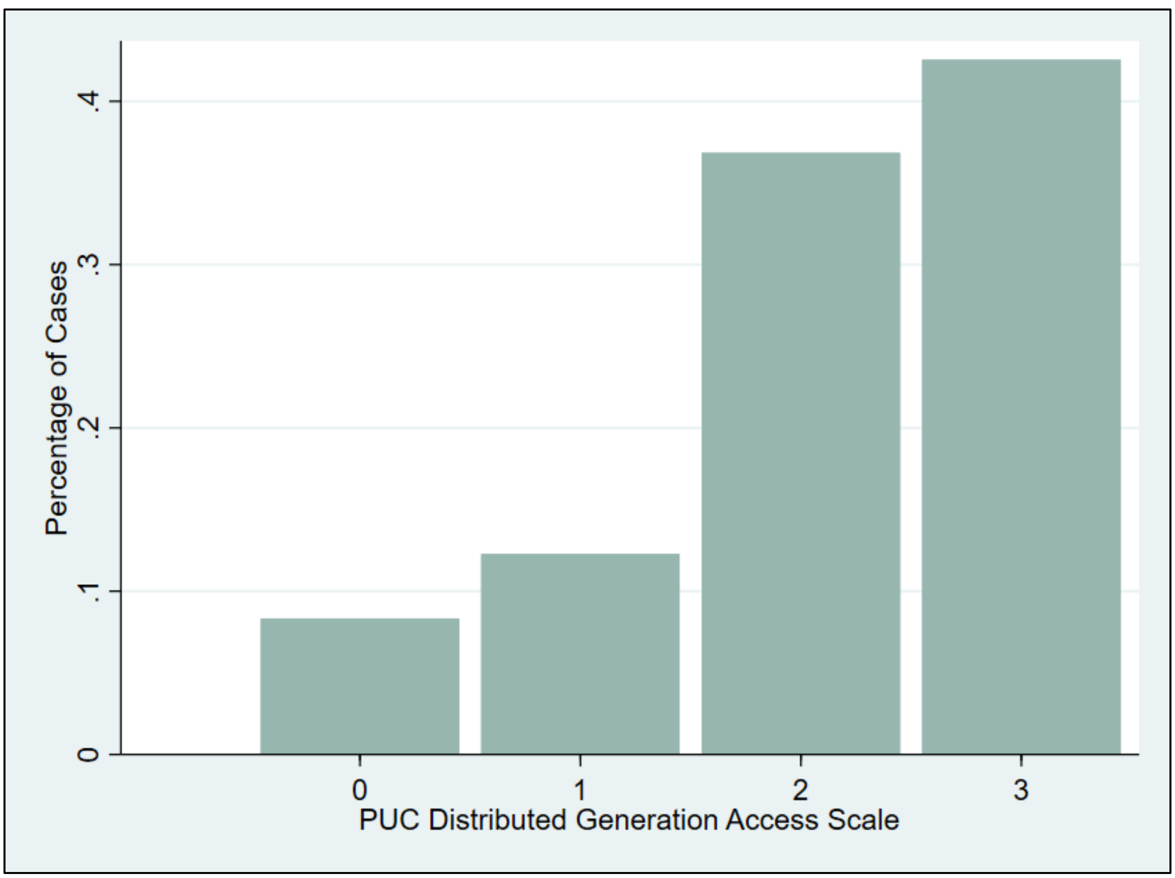

Figure 4.1 PUC Distributed Generation Access Scale, Bar Chart

The figures above reveal the dataset's skew in favor of greater DG access. Similarly, the data is heavily weighted toward the later years in the dataset. Regulatory activity surrounding DG appears mostly routine in earlier years in the dataset and began to accelerate in 2015. 2016 was the busiest year with 72 total decisions, while 2014 was the sparsest year with only 7 decisions. In the latter half of the time interval, state regulators were tasked, in many cases by their legislatures, to conduct reviews and consider updates to net metering and interconnection rules. Figure 4.2 below displays the change over time for each of the four types of decisions on the ordinal scale.

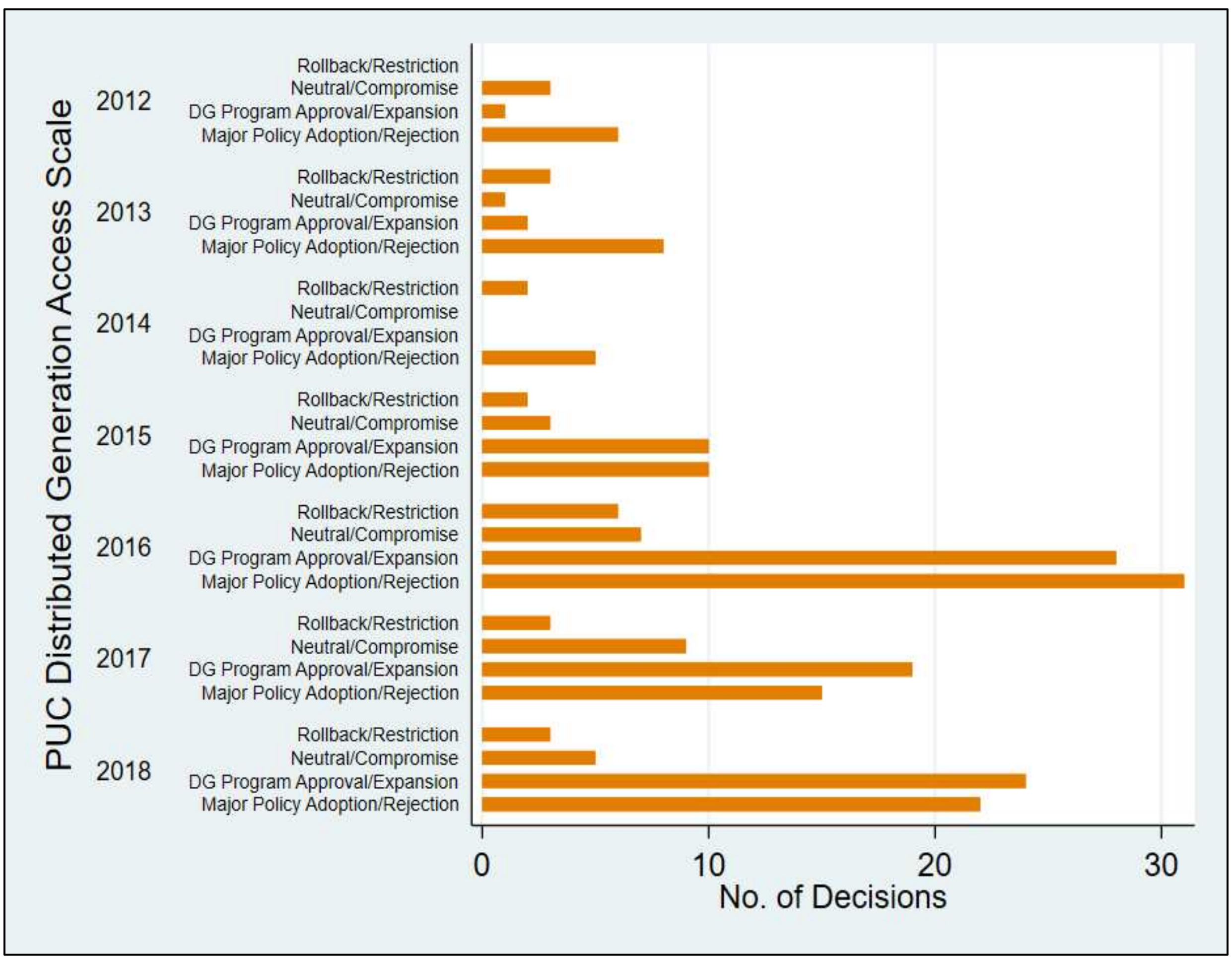

Figure 4.2 Number of PUC Decisions by Coding Type, Change Over Time

Bivariate Analysis

This section lays out hypotheses and conducts bivariate analyses to examine the relationships between DG favorability and political and economic conditions. Before an examination of the PUC ordinal scale, I first revisit DG index scores to test whether certain elements of institutional design significantly impact regulatory favorability toward DG access in a means comparison analysis. Second, I analyze the association of economic factors and power system characteristics on the ordinal PUC ruling scale to gauge whether certain market and regulatory conditions create an environment more conducive for the adoption of pro-DG policies.

1. PUC Structure and the Distributed Generation Index

Following the previous chapter's bivariate analyses, the following hypotheses examine whether the structure of PUCs significantly affect policy outputs measured by the DG index. More specifically, this chapter is examining the effect on policy outputs from the *selection process* of utility commissioners. This project follows the literature on PUCs that suggests the selection processes for commissioners shapes the political relationship between the regulatory body and its statutory overseers (Gormley 1983; Boyes and McDowell 1989; Besley and Coates 2003). Commissions with certain structural characteristics might respond to certain external pressures over others, changing the political calculus across types of PUCs. Hence, the selection process will affect policy outputs in power sector regulation. Commissioners elected by the general public may be more responsive to citizen pressures to keep electricity rates low; or alternatively, allow for greater access to renewable energy. Commissioners that are selected by the legislature may be more likely to align with legislative priorities and act with a greater degree of administrative discretion (Fremmeth and Holburn 2012). If political structure significantly impacts policy outputs, then we might reveal evidence of principal-agent dynamics that potentially militate changes to the status quo. Whether PUC design hinders DG progress due to path-dependency is the central question of this section.

The first hypothesis involves the commissioner selection process most directly and asks whether PUCs with elected commissioners will be more favorable to DG access policies than commissioners with commissioners appointed by the governor. “Elected” status is treated as a dummy variable in this project and is highly unbalanced; with 11 states have elected PUCs and 39 states with appointed commissioners, 202 decisions were made by appointed PUCS, leaving 26 cases made by elected commissioners. The available literature on PUCs suggests elected PUCs might be more apt to engage in pro-consumer behavior than appointed PUCs, because the electoral connection to a voter constituency hypothetically draws commission decision-making closer to consumer interests and away from interests of the legislative body, or alternatively, the regulated community (Fremmeth and Holburn 2012, Gormley 1983, Boyes and McDowell 1989). Research, however, is not conclusive, and some studies have shown that, while PUCs do respond to political pressures, the relationship between consumer interests and PUC outcomes is not clear-cut, nor is an explanation of PUCs’ inclinations reducible to whether commissioners are elected or appointed (Boyes and McDowell 1989; Besley and Coates 2003). Additionally, much of the PUC literature examines changes in electricity rates or billing practices as the outcome of interest, and relatively few studies about the relationship between PUCs and renewable energy policy have been undertaken, despite the fact that PUCs are the regulatory gatekeepers of distributed generation access (Brown 2017). Because increased DG access is a pro-consumer orientation, the first hypothesis below proposes that elected commissioners are more favorable for DG access.

H1: PUCs with elected commissioners are more likely associated to exhibit *higher* DG scores.

The second hypothesis related to institutional structure deals with term limits. While most commissioners serve lengths from four to six years, only six PUCs - Arkansas, California, Iowa, Louisiana, Montana, New Mexico - have term limitations. Only 20 out of 228 datapoints in this chapter represent PUCs with term limits. Term limits increase commissioner turnover; therefore, we might expect commissioners to be less likely to adhere to business-as-usual decision making, which has historically been mostly deferential toward electric utilities. Newer commissioners might be less ingratiated into the utility-regulator policy network and less resistant to policies that would accelerate systemwide transformations. Therefore, the second hypothesis states:

H2: PUCs with term limits will be associated with *higher* DG scores.

The last hypothesis to compare groups against DG scores are bipartisan requirements. Bipartisan requirements remove the possibly of supermajorities in PUCs, forcing compromise between commissioners on sensitive policy issues and moving the body's average ideology closer to the center. Also, an ideologically moderate PUC may be less entangled with, or entrenched against, regulated utilities, which would create an environment more favorable for compromise between regulators and utility corporations. Hence, we expect bipartisan institutional settings to yield gains for distributed generation access:

H3: PUCs with bipartisan requirements are associated with higher DG scores.

I conduct two-tailed t-tests to determine whether the posited relationships are statistically significant. Results from the bivariate analysis are presented in Table 4.3 below:

Table 4.3 Public Utility Commissions and the Distributed Generation Index - Means Comparison Table

Commission Structure	Mean DG Score	*n*
Commissioner Selection		
Appointed	22.54*	266
Elected	14.6*	70
Term Limits		
No	20.60	266
Yes	18.62	42
Bipartisan Requirement		
No	18.63*	168
Yes	21.14*	168
*Indicates statistical significance at $p < 0.001$		

The findings from the means comparison across groups presents implications for the effects of institutional design on regulatory outcomes, some of which are counterintuitive. First, the method of commissioner selection significantly factors into DG score, but elected PUCs appear more resistant to DG access than appointed PUCs, which is the opposite relationship of the proposed hypothesis. Furthermore, the difference in means is substantial; states with appointed PUCs have an average DG access score of 22.5, just above the 48-state median of 22, while states with elected PUCs have an average score of 14.6, just above the 25th percentile of 13. Several factors may be contributing to this result. It may be the case that elected PUCs are responsive to constituent interests, but electorate preferences may not be in favor of increased DG access, as ratepayers tend to prefer keeping electricity bills low, and while rate impacts from increased DG access might rise in the short-term, depending on system attributes.[97] If elected commissioners are more sensitive to rate impacts than appointed commissioners, they may be more hesitant to increasing DG access. Additionally, it must be noted that the majority of elected states are politically conservative. Only a single observed case out of the 228 data points was

[97] Navigant Consulting, Inc., 2013. Distributed Generation Integration Cost Study: Analytical Framework. Prepared for the California Public Utilities Commission.

decided concurrently with a Democratic legislature, another single case was decided alongside a divided legislature, and the remaining cases are associated with Republican legislatures.[98] Because elected states with elected PUCs lean Republican, it will be difficult to isolate the causal effects of carbon or market-based path-dependency on regulatory decision-making from ideological factors.

Aside from method of commissioner selection, the elements of PUC structure do not appear to yield a substantial impact on DG score. Term limits exert no significant influence on DG access. The adoption of bipartisan requirements, however, are significantly associated with DG scores, but the effect is relatively small: states with PUC bipartisan requirements have an average DG score of 21.1, while states without bipartisan requirements have an average score of 18.6. The modest increase in DG access favorability suggests that PUCs with a diverse partisan composition is more likely to find common ground in advancing DG access, but DG policy is likely driven in larger part by other factors.

While we can conclude institutional setting matters, we need more sophisticated methods to reveal the range of factors influencing PUC outputs. Path dependence may be stronger for elected PUCs, if the incentive for reelection is pushes commissioners to maintain low electricity rates. Further controlled comparisons may help tease out these relationships between PUC structure and DG policy. I revisit the question of PUC structure in the section on multivariate analysis later in the chapter.

[98] New Mexico is the elected PUC state with both the Democratic and Divided Legislature data points.

2. *The PUC Scale and the Distributed Generation Index*

Next, I examine the relationship between the state-level DG index results from Chapter Three and the ordinal scale measuring PUC favorability. It will be useful to compare the DG scores with the PUC scale measure to see whether regulatory decisions align with the wider state-level policy environment. If there are significant discrepancies between the state score and PUC favorability toward DG access, we might reveal evidence of regulatory drift, which could be the product of capture by electric utilities seeking to maintain ownership of their generation assets, or at least prevent the possibility of cross-subsidization from increased DG deployment. The next hypothesis assumes that electricity regulators align with the wider state policy environment:

H4: PUCs in states with higher DG index scores are more likely to adopt policy favoring increased DG access.

We expect a positive relationship between DG scores and rank-ordered PUC decisions, with higher-ranked DG decisions arising from state-years with higher DG access scores, and lower PUC decisions delivered in state-years with lower scores. It could be argued that a positive relationship, or potentially a perfectly collinear relationship, is a forgone conclusion, but I argue it is useful to at least rule out the possibility that PUCs would actively work against state clean energy legislation through regulatory decision making. After all, much of the factors included in Chapter Three's index measure represent policies that must be established in statute, so it is worthwhile to determine whether there is any significant variance between a state's statutory and regulatory activities. To test the hypothesis, I conduct Kruskal-Wallis one-way analysis of variance tests to compare the mean DG scores across the four values of the PUC scale. The Kruskal-Wallis equality of populations rank test is appropriate because it allows for nonparametric hypothesis testing of data that are not distributed normally, and as discussed in descriptive analyses, the four-category ordinal variable is unbalanced and weighted towards higher values of two and three along the scale. The null hypothesis for the Kruskal-Wallis test expects the distribution of DG scores to be equal across all levels of PUCs' DG favorability. Results are displayed in Table 4.4 below.

Table 4.4 Kruskal-Wallis Analysis of Variance, Mean DG Index Scores by Ranked PUC Decisions

PUC-DG Scale	DG Score Mean	Std. Deviation	Rank Sum	*n*
Rollback/Restriction	18.11	6.99	1,114.0	19
Neutral/Compromise	24.21	9.28	2,704.5	28
DG Program Approval	24.13	10.26	8,424.0	84
Major Policy Adoption	30.57	9.81	13,836.5	97
Total	26.38	10.44		228
$\chi^2 = 37.605$; $p < 0.001$				

Examining the mean DG scores across categories of PUC decisions reveals a clear trend that PUC decisions more favorable to DG access are associated with higher DG index scores. Additionally, the rank sum column indicates that the distribution of the data is substantially discrepant for different values of the DG decision scale, ranging from 1,114 for rollbacks/restrictions and 13,826 for major policy adoptions. With three degrees of freedom, the chi-squared test statistic of 37.605 easily clears the critical value threshold at the 0.001 level of statistical significance, making it unlikely that the positive association of pro-DG PUC rulings to DG scores is explainable due to random chance. It could be the case that the dispersal of cases is too skewed towards pro-DG access to yield meaningful results. As such, it will be necessary to conduct further tests in order to conclusively state whether PUCs are aligned with their states' wider policy goals, but it is clear that regulatory drift does not manifest as a general trend affecting all 43 states with data collected. Regulatory drift could be occurring in some states due to certain factors, and this question must be revisited in the section on multivariate analysis.

3. PUC Decision Scale and Electricity Markets

This section analyzes the relationship between economic factors and PUC favorability toward distributed generation. To determine whether economic conditions and power system characteristics have a significant impact on the PUC's policy orientation, I sort cases into groups above and below the means of economic variables and describe the frequency and percentage of observations within each classification of PUC decisions. Then, I utilize two-sample Wilcoxon rank-sum tests to determine whether the sample of cases across categories of the independent variables have statistically different populations when compared to the PUC ruling value for DG access. Similar to the reasons that I conduct a Kruskal-Wallis test above on DG scores and PUC decisions, the Wilcoxon/Mann-Whitney tests allows us to determine the significance of relationships for grouped variables with nonparametric analysis, because we cannot assume normal distribution for these cases.

First, I examine whether the electricity regulatory model led to more favorable DG access decisions. Chapter Three explored the differences in DG index results between states with vertically integrated markets, in which electricity customers are locked-in to the incumbent utility dependent upon their geographical location, and restructured states, in which customers have the option of choosing their electricity supplier, which might be a different entity from the utility that provides service to that property. The analysis found that restructured states are generally more likely to have policies favorable for DG access, and carbon-based path dependencies exert less of a hold on policy outcomes. Similarly, we expect PUCs in restructured states to be less path-dependent in perpetuating the long-standing utility system of centrally operated power, and they will make decisions that are more beneficial for DG access.

H5: PUCs in restructured states will be more likely to adopt policy advancing DG access.

Table 4.5 below presents the results from a cross-tabular analysis of PUC decision-making against the type of electricity market, organized into restructured and vertically integrated states.

Table 4.5 Wilcoxon Rank-Sum Analysis: PUC Decisions by Type of Market Regulation

	Electricity Market		
PUC-DG Scale	Restructured	Vertically Integrated	Total
Rollback/Restriction	4 (4.9%)	15 (10.2%)	19 (8.3%)
Neutral/Compromise	8 (9.9%)	20 (13.6%)	28 (12.3%)
DG Program Approval	25 (30.9%)	59 (40.1%)	84 (36.8%)
Major Policy Adoption	44 (54.3%)	53 (36%)	97 (42.5%)
Total	81 (100%)	147 (100%)	228 (100%)
Rank Sum Analysis			
Rank Sum	10,456.5	15,640.5	26,106
Expected Rank Sum	9,274.5	16,831.5	26,106
Median PUC-DG Value	3 (Major Adoption)	2 (Program Approval)	
Z = -2.678; p = 0.0071			*N* = 228

Note that restructured is coded as a dummy variable, with "0" states having vertically integrated markets and "1" states having restructured markets. With a z test statistic of -2.678, the Wilcoxon rank-sum analysis indicates significant differences between restructured and vertically integrated states with a very low probably (p = 0.0071) that variation in distributions is random. Higher rank sum figures indicate more instances of pro-DG PUC decisions, and equality with the expected rank sum would leave us unable to reject the null hypothesis that the distributions are equal. Notice that the rank sum for restructured states is higher than the expected value, while the rank sum for vertically integrated states is lower than the expected value. This shows that restructured states have a distribution with a greater density of data points toward the higher end of the PUC scale than the expected rank sum, while cases in vertically integrated states are clustered slightly lower on the scale than the expected rank sum. This aligns with the differences in central tendency between electricity market types; vertical states have a median PUC coding of two: program approval, while restructured states have a median value of three: major policy adoption, suggesting that the case distribution is shifts rightward for markets with restructured status. The rank sum test indicates that PUCs are somewhat more favorable toward DG access in restructured states.

For the final portion of this chapter's bivariate analyses, I examine the relationship between PUC favorability and utility market concentration. This hypothesis follows the logic of the earlier analysis that shows more concentrated markets are more favorable to DG access. Chapter Three speculated that states with large monopoly utilities may be better suited to facilitate DG integration than states served by a greater number of smaller utilities, because large utilities have greater technological capacity and a larger rate base to diffuse rate increases that might result from higher penetration levels of distributed systems. States with more fragmented markets may be less able to address cost-shifting or cross-subsidization resulting from high DG deployment. In testing this hypothesis, we are clarifying whether this counter-intuitive logic is at work to the same degree as in the analysis of DG index scores. Alternatively, we might discover a weak relationship to be probed further in the multivariate analysis.

H6: PUCs in states with concentrated markets are more likely to favor DG access policy than PUCs in competitive markets.

Like the exercise above, I conduct a two-sample Wilcoxon rank-sum test to determine whether the distributions between states with competitive and concentrated utility markets are significantly different. I separate the independent variable of utility market concentration into two groups. "Concentrated" states, coded "1," represent electric monopolies and duopolies, defined as states in which one or two utilities serve three-quarters or more of the state's electricity customers. “Competitive” states, coded “0,” include all other states. Results are presented in Table 4.6 below.

Table 4.6 Wilcoxon Rank-Sum Analysis: PUC Decisions by Level of Market Concentration

	Utility Market Concentration		
PUC-DG Scale	Competitive	Concentrated	Total
Rollback/Restriction	13 (7.9%)	6 (9.4%)	19 (8.3%)
Neutral/Compromise	19 (11.6%)	9 (14.1%)	28 (12.3%)
DG Program Approval	62 (37.8%)	22 (34.4%)	84 (36.8%)
Major Policy Adoption	70 (42.7%)	27 (42.2%)	97 (42.5%)
Total	164 (100%)	64 (100%)	228 (100%)
Rank Sum Analysis			
Rank Sum	18,915.5	7,190.5	26,106
Expected Rank Sum	18,778	7,328	26,106
Median PUC-DG Value	2 (Program Approval)	2 (Program Approval)	
$Z = 0.329$; $p = 0.747$			$N = 228$

The Wilcoxon test fails to show any statistically significant difference between competitive and concentrated states, with a z statistic of 0.329 and a prohibitively high p-value of 0.747. Both groups have a median PUC decision coding of two – program approval – with very minor discrepancies from the rank sums and expected values. Our inability to reject the null hypothesis cuts against the previous chapter’s findings that electricity systems operated by large utilities are more conducive to DG access. However, since a clear relationship between market ownership and DG favorability was not found in either direction, it is still possible that market fragmentation poses barriers to DG integration. While we cannot draw meaningful inferences on the relationship between market concentration and PUC behavior here, the next section carries out a more comprehensive analysis of the regulatory and economic factors affecting PUC’s propensity to adopt DG access policy. There, we might uncover potentially complex relationships between market structure and regulatory outputs.

Multivariate Analysis

The remainder of the chapter is devoted to mapping out the political, regulatory, and economic factors that influence PUCs' likelihood to adopt DG access policy. First, I lay out hypotheses that propose to capture the effect of path dependence on PUC decision making. Second, I describe the multivariate design to be used for this study and provide analysis for the model results.

Independent Variables

The set of relationships to be modelled in a multivariate design will reflect the economic indicators, technical constraints, regulatory elements that potentially influence the probability that PUC decides in favor of enabling expanded distributed generation. I organize predictive factors into two categories: political/regulatory and economic/technical factors.

1. *Political & Regulatory Factors*

The primary independent variable of interest is the influence of the established regulatory environment on PUC decision making. If path dependence is perpetuated by characteristics of the state's energy infrastructure, we would expect the establishment of public policy objectives intended to alter attributes of the energy system for environmental goals would allow PUCs more discretion to deviate from the status quo in adopting rules for distributed generation access. Policies incentivizing utilities away from conventional industry behavior might prepare the electricity system for technological shifts. The resultant regulatory scores from the Chapter

Three factor analysis will be used to measure the state's regulatory regime.[99] The first hypothesis to be introduced to the multivariate analysis is stated:

H7: PUC decisions in state-years with a more robust utility regulatory regime will be more favorable to DG access.

Since this project proposes path dependency might be weakened with a robust regulatory regime with explicit policy objectives directing a systemic shift, it is necessary to control for the broader political climate in which PUCs are situated. It could be the case that PUC decision making is shaped more strongly by electoral trends rather than established regulatory frameworks. To control for partisan influence on PUC outcomes, the multivariate model includes the percentage of state legislature seats occupied by Democrats. State legislatures are responsible for directing and overseeing the utility commission, though the degree of authority legislatures exert over electricity regulators varies across states.[100] A result showing a stronger predictive effect for party composition over the regulatory environment might be evidence of regulatory drift. For example, a state that has adopted environmental or conservation objectives (measured by the 'Regulatory Policies' variable) could have a PUC that is less likely to promulgate rules expanding DG access than other states, despite the existence of a regulatory framework designed to increase renewable electricity generation. Environmental policy regimes may be adopted during legislative sessions with greater Democratic control, and PUCs in subsequent sessions may utilize their jurisdiction to deny or delay decisions regarding DG access at a more granular scale. Because Democrats are more likely to support policies to expand renewable energy, we

[99] Regulatory scores were transformed by their natural logarithm to mitigate heteroskedasticity.
[100] National Conference of State Legislatures, 2019. Engagement Between Public Utility Commissions and State Legislatures. https://www.ncsl.org/research/energy/engagement-between-public-utility-commissions-and-state-legislatures.aspx

expect a positive relationship between Democratic composition and PUC decisions regarding DG access.

H8: PUC decisions in state-years with a greater percentage of Democratic state legislators will be associated with *higher* probabilities for pro-DG decisions.

In addition to the new hypotheses listed above, this project tests the hypotheses examined in the previous section on bivariate relationships. *H1* stated that PUCs with elected commissioners would be associated with states that rate higher on the constructed distributed generation policy index. Estimating the effect of commissioner selection type is necessary for understanding the political drivers of regulators' decision-making. If institutional design meaningfully influences policy outputs, the findings will have significant implications for the theories of path dependency and regulatory drift as deployed by this dissertation. For this chapter, we expect a similar relationship between PUC selection method and the favorability of PUC decisions toward DG access that were found in the bivariate analysis, the findings of which were the opposite of this chapter's initial hypothesis:

H9: PUC decisions in states with elected commissioners will be associated with *lower* probabilities of pro-DG decisions.

If we are unable to reject this null hypothesis and the relationship is revealed to be in the *opposite* direction, this might be evidence of regulatory drift in PUCs with appointed commissioners, since appointed commissioners would act with more hesitation toward adopting expanded DG policies. In this scenario, we could posit that the retrospective voting might drive the electorate to replace the governor if they are unhappy with the actions of their PUC appointments. On the other hand, if the null is rejected and the relationship is in the expected inverse direction, this could be evidence that electoral politics are a more constraining force stymying the adoption of DG access policies. By extension, we might infer that cost-shifting concerns are appreciated more directly by elected commissioners, since voters have the opportunity to remove them if they disapprove of electric cost increases. A significant result would be instructive for principal-agent dynamics in legislative-regulatory relations in either case.

The next hypothesis seeks to determine whether the type of utility by *class of ownership* would impinge the PUC's probability of adopting pro-DG policy. The full reach of PUC jurisdiction extends only to investor-owned utilities (IOUs) in most states, while electric cooperatives and public power entities usually enjoy relative autonomy from state regulators. Plausibly, a PUC in a state that is primarily served by IOUs would be more sensitive to utility concerns over cost-shifting. Conversely, a state served in larger part by cooperatives and publicly owned utilities may be less reliant on centrally operated large-scale power facilities, and instead by more favorable to distributed energy resources, since these utilities operate at a smaller scale and often provide service to customers in more geographically remote locations. States with larger IOUs might resist enabling greater DG access because it would pose a greater risk to utility revenue. Hence, we expect PUCs to be less likely to adopt pro-DG policies if they oversee larger private corporations:

H10: PUC decisions in state-years with higher percentage of customers served by investor-owned utilities will be associated with lower probabilities for pro-DG decisions.

The final political/regulatory variable controls for the restructuring status of states. The bivariate analysis found that restructured states tend to deliver pro-DG policy outputs more often than states with vertically integrated utilities, likely because increasing the diversity of electricity providers comes with a concurrent increase in options for customer supply. Generally, restructured states have a track of adopting regulations more favorable to DG access, so we expect that PUCs in restructured states would align with the trend previously posited by *H5*: PUCs in restructured states will be more likely to adopt policy advancing DG access.

2. Economic & Technical Factors

Following the previous chapter, we are first interested in the relationship between the percentage of coal generation in the state's energy mix and the probably of a positive outcome for DG access policy. The expected relationship is in the same direction as the Chapter 3 analysis, which found that, as the ratio of coal in the electric generation mix increased, state-years were observed to have lower scores on the DG index. Additionally, the impact of coal's prominence in the energy portfolio has differential effects across geographic region, and we would like to control for regional effects in estimating the magnitude of the association. Hence, the multivariate model contains an interaction term that estimates the significance of coal's ratio in each of the four census regions:

H11: PUC decisions in state-years with higher proportions of coal generation will be associated with higher probabilities for pro-DG decisions.

Next, the multivariate analysis must attempt to model the effects of technology shifts throughout the power system on PUC decision-making. If regulatory and economic path-dependencies bear upon policy outcomes at the utility commission as this project's guiding theory suggests, the short-term costs of increasing the amount of distributed generation on the electricity grid would sway decision makers away from directly supporting grid transformations, potentially presenting further risks to the electric provider or rate base. One method to directly test whether PUC decisions are sensitive to cost-shifting concerns would be to model the relationship of net metering uptake and the probability of pro-DG outcomes. Skeptics of expanded DG policy warn that higher market penetration of rooftop solar and other net metering-eligible systems would accelerate cross-subsidization between customer classes, unfairly requiring higher bills from non-net metering customers to pay into utility infrastructure (Barbose 2017).

However, the inclusion of a net metering variable might present issues in terms of identifying a path of causality. While net metering uptake is plausibly related to regulatory drift in DG policy activity, including market penetration as a predictive factor for PUC outcome potentially introduces an endogeneity problem, since the PUC's orientation toward DG may presuppose higher net metering levels. It could be the case that PUC favorability toward DG access and high net metering penetration are both responses driven by the same underlying factors. Instead of measuring the association of net metering penetration levels on PUC favorability toward DG policy, I include a variable to capture the perceived technical constraints of the distribution system. The EIA publishes data on the number of distribution circuits for each load-serving entity, and I sum the number of distribution circuits across utilities and divide by the state's total generation nameplate capacity to create a proportional metric for distribution capacity. It must be noted that this variable – number of distribution circuits/generation capacity in megawatts (MW) - is an imperfect proxy for true *hosting capacity*, which can widely vary geographically within states as a function of physical system characteristics (Ismael et al. 2019). However, for the purposes of this study, this will be a useful control for capturing the overall accessibility of a state's distribution system. Since the EIA only begun keeping data on distribution systems since 2013, the multivariate model excludes PUC decisions made in the year 2012, which eliminates ten observations for a total *n* of 218. I hypothesize that states with a higher number of circuits per MW will also have more favorable PUC decisions, as the system is better able to integrate new resources located behind customer meters.

H12: PUC decisions in state-years with a greater number of distribution circuits per megawatt of generation capacity will be associated with *higher* probabilities for pro-DG decisions.

The effectiveness of distribution capacity as a driver of pro-DG decisions might be conditional upon other technical attributes within the state. One method to capture unmodeled power system characteristics would be to interact the optimized circuits variable with states' average electricity prices. Electricity price serves as a rough proxy for unspecified factors, but since this project seeks evidence that regulatory and economic path-dependencies bear upon policy outputs, electricity prices would also have a straightforward effect on PUCs, as commissioners must consider direct consumer impacts in their decision-making. To determine whether distribution capacity has differential effects along the spectrum of electricity prices, we include an interaction term between number of circuits and electricity price for the state-year.

Finally, to tie together the regulatory and economic strands of path dependency, we want to test whether utility market concentration is related to the PUC's orientation toward distributed generation. While the bivariate analysis did not find any conclusive relationship between DG favorability and concentrated markets, it will be useful to include a more precise measure of market concentration in this section, as a multivariate analysis will allow us to untangle the potentially complicated regulatory and economic environment that this project attempts to map out. As such, we restate the hypothesis to be tested in the multiple regression:

H13: PUCs in restructured states will be more likely to adopt policies expanding DG access.

While a straightforward effect of market concentration on PUC output is unlikely, I propose that market concentration plays a moderating role in the association between the state's regulatory regime and the likelihood of pro-DG PUC decisions. If fewer entities control a greater proportion of the electric market share, then the chances of regulatory drift may increase, because PUC decisions would be hesitant to upend the revenue model encompassing that is supported by a large percentage of the rate base. To measure market concentration, I collected data on state-level electricity sales in units of megawatt hours (MWh) and added together the sales percentages from the state's two largest utilities. The chapter's final hypothesis is stated below:

H14: Greater regulatory scores will be associated with *higher* probabilities for pro-DG PUC decisions in state-years with *lower* levels of market concentration.

Multilevel Mixed-Effects Ordered Logit Model

The model most useful in investigating the probability of PUC favorability toward DG access across state-year dyads is a mixed-effects ordered logistical regression, with cases nested within states in a hierarchical structure. An ordered logit is necessary to capture the difference in likelihood across the four potential outcomes of the categorical variable that measures PUC decisions. The ordinal model allows us to observe the direction of significant statistical relationships among the predictors and commission outcomes. Random effects parameters were set for the "year" and "state" grouping variables, with states nested within years, and fixed effects specified for the predictor and moderator variables.[101] Specification of random effects is useful in accounting for the unobserved heterogeneity within states and years that could be driving PUC decision making outside the selection of independent variables. Additionally, random effects afford greater confidence in our ability to draw general inferences on PUC

[101] Hausman specification tests were conducted to determine that the mixed effects model with random effects parameters set at the grouping variables are appropriate.

decision making in across time and in other types of DG cases. The model's results are presented in Table 4.7 below.[102]

Table 4.7 Multilevel Mixed-Effects Ordered Logit Regression: Effects of Power Sector Indicators on the Probability of Pro-DG PUC Decisions

Independent Variables	Logged Odds	Std Error	P-value
Regulatory Policies	5.337	1.982	0.007***
Utility Market Concentration (% MWh)	3.953	2.620	0.131
Regulatory Policies * Market Concentration	-9.624	3.233	0.003***
Proportion of Coal-Sourced Electricity	-2.989	3.233	0.042**
Coal Generation * Region			
Northeast	2.828	1.488	0.057*
South	3.180	1.623	0.050**
West	2.760	1.471	0.061*
Elected PUCs	-0.849	0.569	0.135
Distribution Capacity (no. voltage-optimized distribution circuits/total DG capacity)	0.908	0.568	0.041**
Electricity Price	-0.001	0.001	0.169
Hosting Capacity * Electricity Price	-0.001	0.001	0.039**
State Legislature Composition (% Democrat)	0.097	0.024	0.003***
Investor-Owned Utility Market Share (%)	-0.620	1.459	0.671
Restructured Electricity Market	-0.758	0.493	0.124
Cut 1	3.767	2.008	
Cut 2	5.002	2.038	
Cut 3	7.452	2.136	
Constant (year)	4.32e-34	5.67e-18	
Constant (state)	0.632	0.614	
N(states) = 43; *N*(years) = 6; *N*(total) = 218	Wald's $\chi^2(17) = 36.62$; $p < 0.005$		
Random Effect Parameters, Likelihood-Ratio Test:	$\bar{\chi}2(01) = 1.90$; $p < 0.10$		

Results

The mixed logit model finds support for several of the stated hypotheses with legislative partisan composition as the strongest predictor, but some null hypotheses cannot be rejected in this

[102] The effects of the categorical region variable independent of the coal ratio variable were excluded from the output table.

multivariate design. First, I briefly describe the null results that fail to show a statistically significant relationship, then I will discuss the significant findings and their implications for the theory of path dependency.

It appears that market concentration does not have a significant effect on the probability of pro-DG outcomes at the PUC, at least as it is formulated in the model as a percentage of the state's total megawatt hours from the two largest utilities. The absence of a direct effect on PUC outcomes is consistent with the findings of the Wilcoxon rank-sum test displayed in figure 7, which did not show a meaningful difference between "concentrated" states, defined as states in which one or two utilities provide three-quarters or more of the state's electricity supply, and "competitive" states, defined as all other states. Despite this finding, market concentration does interact with the state's regulatory environment as a significant predictor of PUC outcome, which is discussed further below.

The method of commissioner selection is also not significantly associated with PUC favorability toward DG access; elected commissioners are no more or less likely to favor pro-DG policy decisions than appointed commissioners within this model. On the surface, this might exclude the possibility that selection method creates different principal-agent relationships and therefore divergent policy outcomes, but some considerations on the true relationship between selection type and the probability of policy adoption must be noted. Primarily, the distribution of observations results in a data sparseness issue with the dependent variable. Of the 228 total PUC decisions coded, 26 were made from elected PUCs, comprising just under one-tenth of the dataset. Of these, only two observations were made in state-years that did not have Republican control of the legislature. One of these cases was decided alongside a divided government, leaving only one decision to be made alongside a majority-Democratic legislature. Both data points originate from the same body: New Mexico's Public Service Commission.

Due to the unbalanced sorting of cases, we are unable to isolate the effect of commissioner selection from the effects of broader partisan forces. If we were to find a significant relationship in this dataset, we would approach the results with caution, since the majority of elected PUCs happen to be in Republican-leaning states, and variation in DG favorability could be explainable by the true underlying driver of partisanship rather than institutional design. The sparseness issue could be rectified by expanding the time period of the sample, or by increasing the kinds of regulations coded as DG decisions. From this analysis, however, we are unable to establish whether selecting commissioners via elections meaningfully impacts the PUC's likelihood of adopting pro-DG policy. Unfortunately, this leaves any conclusions of possible principal-agent dynamics shaping PUC decisions on murky ground.[103]

Now I turn to discuss the significant relationships and their implications for path dependence. First, the null of *H7* can be rejected, as the state's established regulatory framework positively impacts the PUC's favorability toward DG policies. While this aligns with the expected direction, it must be emphasized that the causal nature of the relationship is not clear-cut, as the significant effect of state regulatory scores is questionable in other model iterations. Regulatory scores significantly impact the probability of pro-DG decisions until one controls for partisan composition; including the effect of the percentage of Democratic legislators washes out

[103] Cross-tabular analysis confirms that we should be wary of inferring any causality from the "elected" institutional structure for PUCs. When comparing the means of state regulatory scores across quantiles of Democratic seats by elected/appointed PUCs, partisan control is responsible for far greater variance than commissioner selection method. The differences in regulatory scores between the lowest and highest quartiles of % Dems is about 2 standard deviations, while variation from elected to appointed commissioners is about 1/3 standard deviations. See Appendix for more information.

any independent effects from the established regulatory regime, suggesting that partisan composition is the true driver of pro-DG rules.

However, as hypothesized, regulatory frameworks do have differential impacts across different levels of utility market concentration. The analysis finds that a significant interaction between market concentration and regulatory regime is at work; as the level of market concentration *decreases*, regulatory scores have more positive effect on the probability of a pro-DG decision, while effects on probability are relatively flat or negative as the level of market concentration *increases*. The direction of the relationship and moderating effect is displayed in figure 9 below. Each subgraph represents one of the four possible PUC decision outcomes, with the y-axis representing the probability the decision type is rendered and the x-axis representing the natural log of the state-year regulatory score. Each slope indicates a different level of market concentration. The red line indicates a state-year in which the two largest utilities supply 70% of the state's total electricity sales in megawatt hours, which is the approximate mean. The blue line and green lines show the slope of regulatory scores and decision probability at 40% and 100%, which represents roughly two standard deviations above and below the mean, respectively.

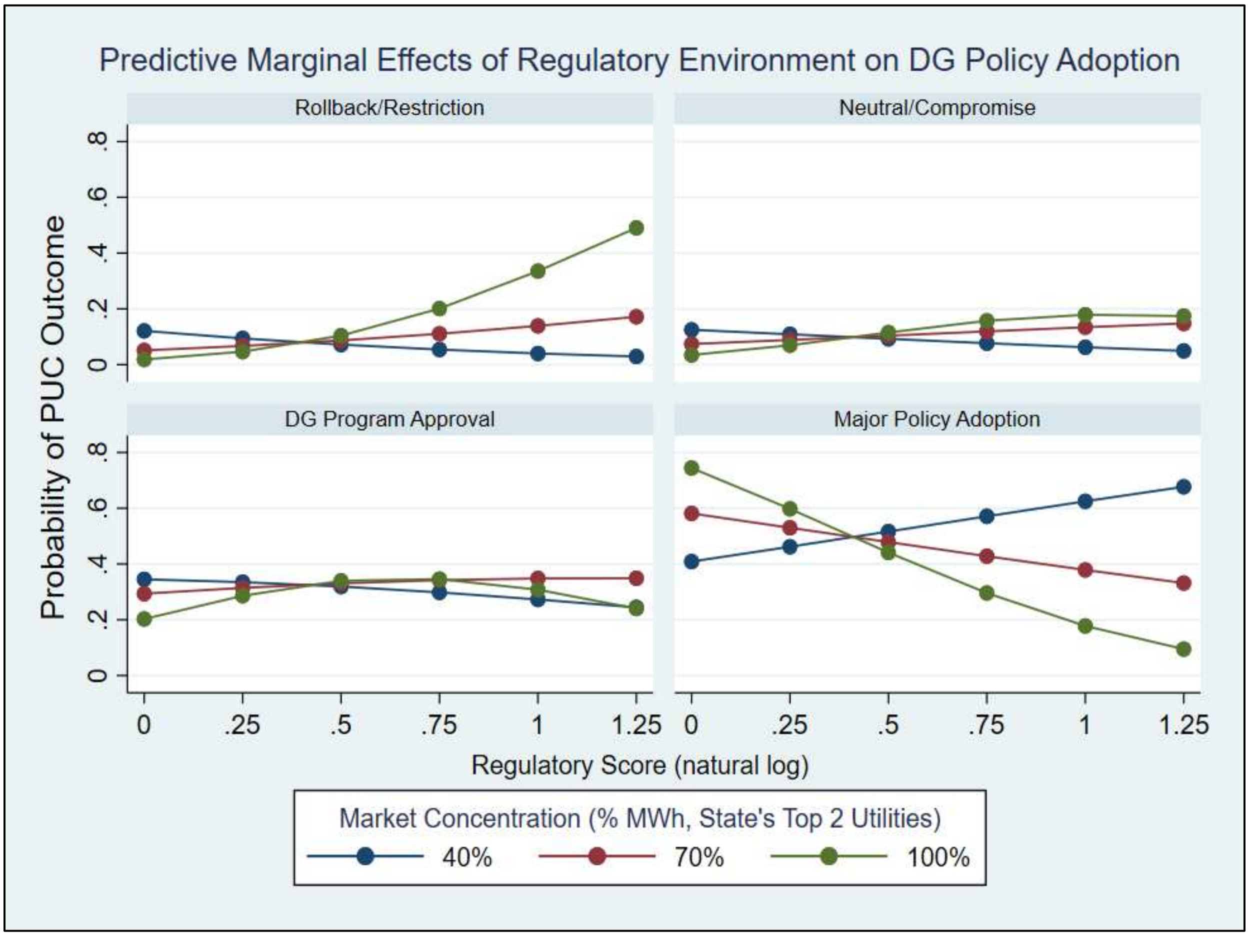

Figure 4.3 Regulatory Regime and PUC Outcomes, Moderated by Market Concentration

Examining the top-left box in Figure 4.3, we observe a clear trend: the probability of rollbacks and restrictions increases as the regulatory score increases for state-years with higher market concentrations. On the opposite end of the scale, the probability of pro-DG decisions decreases with higher regulatory values for more concentrated utilities, while regulatory regime elicits a strong positive effect in states with more fragmented utility markets. Following the logic of the path dependence theory, it is tempting to conclude the establishment of regulatory policies have an entrenchment effect on major utilities and their overseers, which would be revelatory of regulatory drift. Drift occurs when the regulatory entity is working under the auspices of a regimented statutory authorization, minimizing their discretion or flexibility in satisfying public policy objectives (Eisner 2017). Because the regulatory charge for PUCs has historically been relatively myopic -to secure utility revenue at just and reasonable rates - contemporary policies that impose objectives of environmental protection or innovative technologies often conflict with the constitutional or statutory structure of PUCs. Additionally, electricity regulation is a tight knit network of PUCs and regulated entities, in which electric corporations must maintain a close relationship to PUCs through information sharing, providing testimony in rate cases, regular process of resource plan approval, etc. It may be the case that PUCs tied to larger utilities are more likely to deny major expansions of DG access since this would cut against the traditional posture of electricity regulators by potentially introducing higher short-term costs and longer-term risks to the conventional utility business model.

The ordered logit model also found the proportion of coal in the electricity mix to be a significant predictor of DG decisions. This result is consistent with the findings of the previous chapter, which found that DG index scores increased as the ratio of coal generation decreased. Figure 4.4 displays the slopes for each of the four PUC decision types. The probability of rollbacks/restrictions and neutral/compromises increases in the higher-end range of coal generation, while the probability of major policy adoption decreases. The slope of DG program approvals is more wavering but decreases toward the highest values of coal generation.

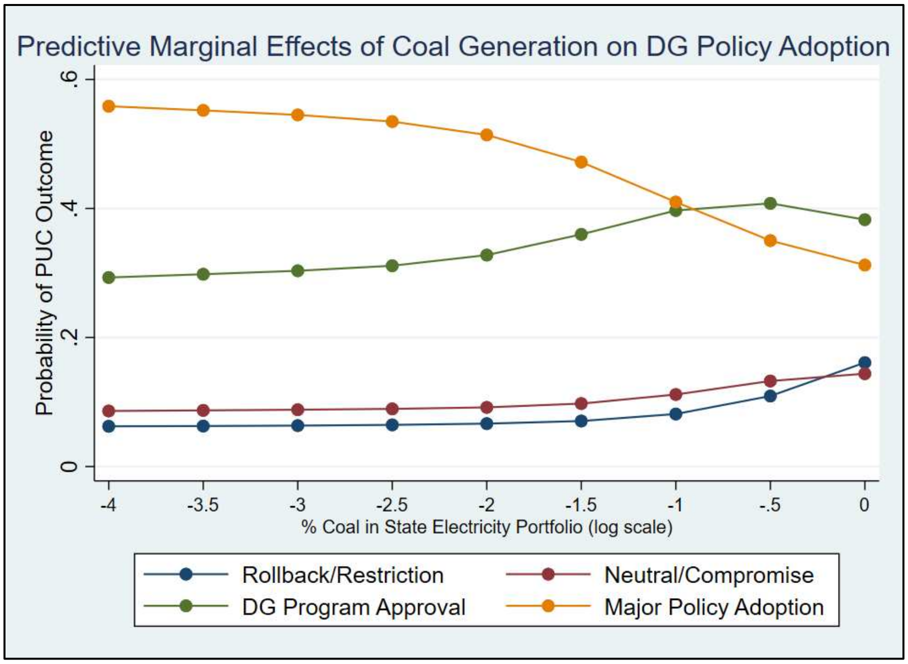

Figure 4.4 Marginal Effects of Coal Generation on PUC DG Decisions

While the trend is clear in three out of four of the decision types in the figure above, the true impact of coal generation on regulatory actions is more complicated. A more subtle analysis that accounts for the moderating effects of geographic region shows that, while coal generally is negatively associated with pro-DG decisions, the substantive impact of coal varies greatly. Figure 4.5 below displays the same relationship of coal and probability of PUC outcome but separates the probability slopes by region.

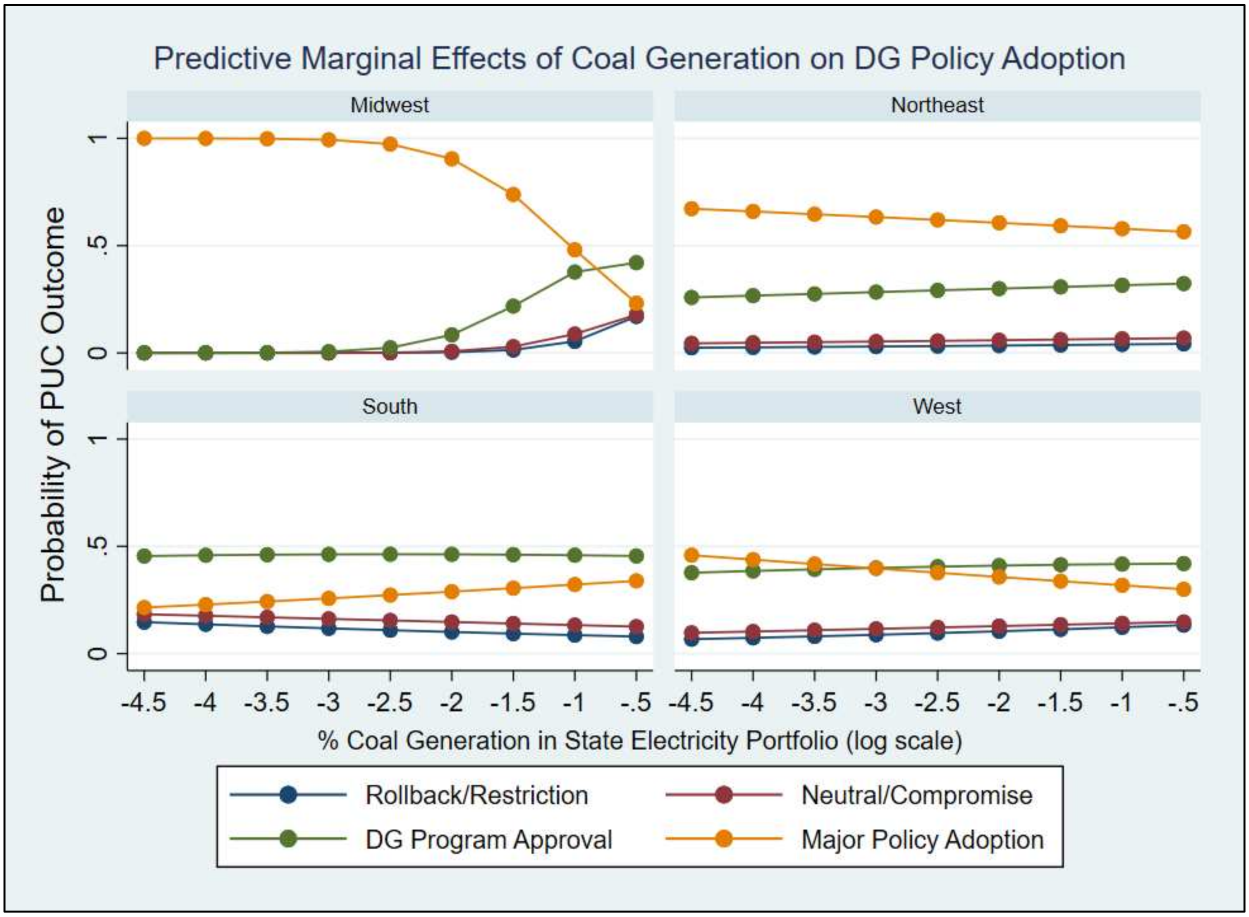

Figure 4.5 Marginal Effects of Coal Generation on PUC DG Decisions, Conditional upon Region

The most standout region is the Midwest, in which ratio of coal generation bears the largest negative impact on the probability of major DG policy adoptions, and slight increases in probability at the high-end of coal ratios for the other decision types. One could say that evidence for *H11* is strongest in the Midwest, while the substantive effect of coal generation is muted in other regions. The West and Northeast share similar trends of a slightly negative slope for major policy adoptions and slightly positive slopes for rollbacks/restrictions and neutral/compromise decisions. The slopes for DG program approval are slightly positive as well, but this is the reverse direction of the hypothesis. Because DG programs are proposed by utilities, it may be that PUCs would be more likely to grant expanded DG access through the framework of the utility operation, since the utility would not bring a proposal to the PUC if the utility did not already accept a certain amount of risk emanating from the integration of distributed renewables. In other words, a coal-heavy mix would not be threatened by DG programs if they are managed by the utilities that own coal assets.

The South has more perplexing slopes, with the probability of adopting major DG policies *increasing* with a higher percentage of coal generation. Part of the problem with identifying the effects of coal in the South is that, while southern states generally have fossil-fuel heavy portfolios, they are often supplied in larger part by natural gas than coal. States such as Tennessee, Oklahoma, Texas, and Louisiana have rich natural gas resources, for example. Additionally, Texas and Oklahoma have high proportions of wind generation, further minimizing their reliance on coal power. The census designation might also create complications, as Delaware Maryland, Virginia, and Texas are all coded Southern states, yet have relatively high proportions of renewable energy in the generation portfolio.

Lastly, this model finds distribution capacity to be a significant positive influence on pro-DG decisions, including the significant interaction effects with electricity price. Figure 4.6 on the next page displays the relationship, organized into subgraphs by PUC decision type. Each slope represents a value of electricity price, with 11.1 cents/kWh as the mean 8.1 cents/kWh as one standard deviation below the mean, and 14 and 16.9 cents/kWh as one and two standard deviations above the mean, respectively. The positive effect of the number of optimized circuits on pro-DG decisions are felt most prominently in states with lower electricity prices, which is mostly clearly observable in the bottom-right graph displaying the probability of major policy adoptions. At the highest electricity prices, the slope is close to flat, if not slightly negative, while the blue line representing low electricity prices is positive. We observe the reverse relationship at the other end of the scale; increasing distribution capacity significantly decreases the probability of rollbacks/restrictions in states with lower electricity prices more so than states with high electricity prices.

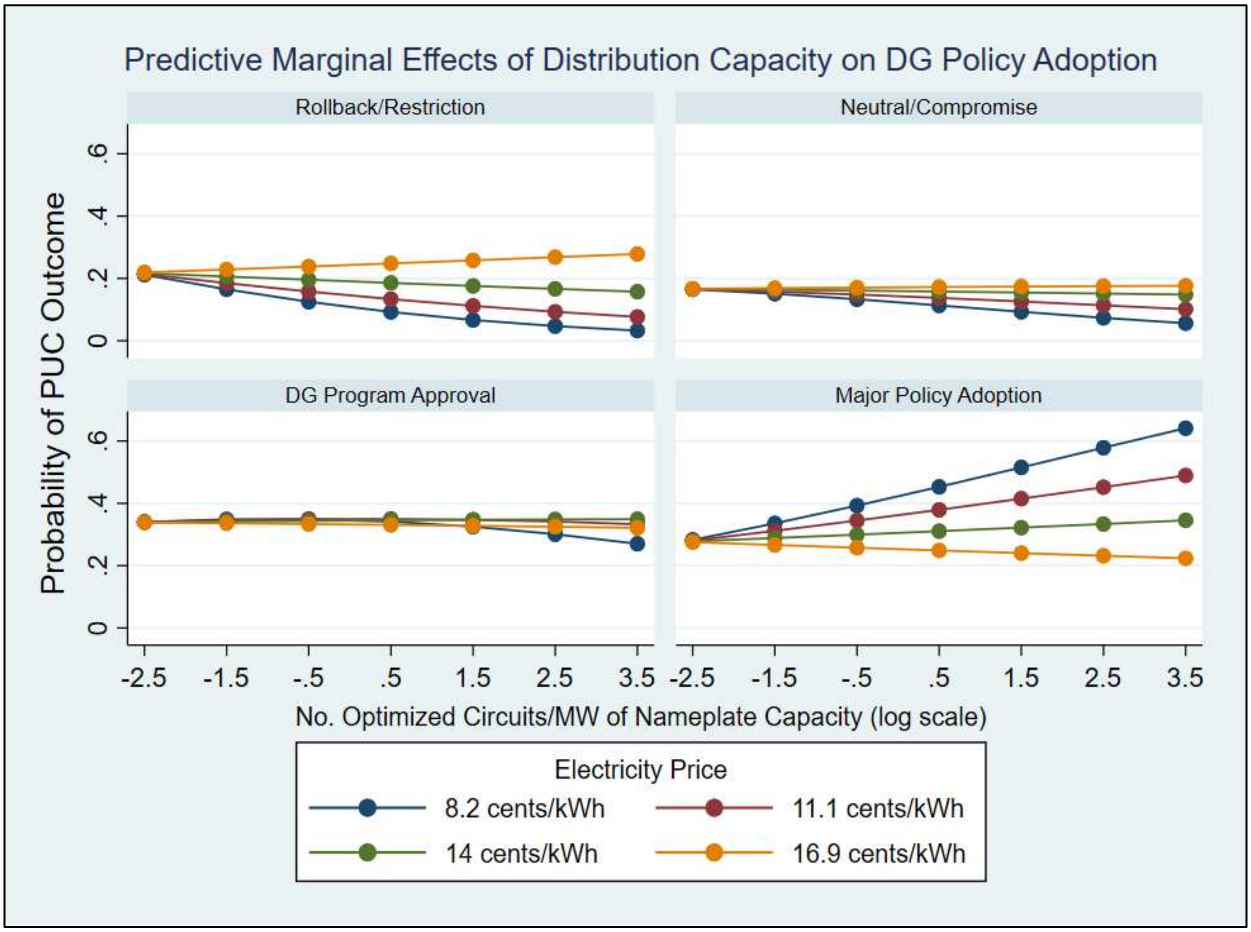

Figure 4.6 Distribution Capacity's Effect on DG Policy, Moderated by Electricity Price

This finding has important ramifications for DG policy. First, recall the discrepancy between electricity *costs* and electricity *bills*; states with higher energy costs tend to establish policies to reduce the energy burden to its citizens, such as energy efficiency resource standards and rigorous energy standards for home appliances. So, it would follow that increasing the number of optimized circuits on the distribution grid would not yield a positive measurable effect on the likelihood of a pro-DG outcome, if the state has already conducted a number of policy actions to improve its electric infrastructure. Second, since lower electricity costs amplify the positive effect of higher numbers of voltage-optimized distribution circuits, renewable energy advocates in rural states might find greater success in advancing their policy agenda if they focus their efforts toward expanding technical capacity. An approach that emphasizes the value proposition to customers and utilities of updating the distribution grid to enable the integration of renewable energy systems might give advocates the best chance of success when proposing instruments to expand DG access to the PUC.

Despite the findings that regulatory, economic, and technical variables significantly factor into PUC's likelihood to adopt DG policies, the legislature composition variable is the clearest driver of policy change among the set; the percentage of statehouse seats occupied by Democrats has the largest impact on the probability of policy adoption. Yet we can be relatively assured that partisan control is not the end-all for explaining policy change in distributed generation access. While not much policy activity expanding opportunities for DG occurred in Republican-controlled legislatures, activity is significantly higher in cases with divided government. As the analyses of technical factors show, particularly in Figure 4.13, the falling cost of innovative technologies creates the opportunity to expand infrastructure capacity to facilitate the integration of DGs, especially in states that have not yet seen progress in updating their distribution grid. These results have important implications for our understanding of the politics of innovation; institutions become more receptive to potential systemic transformations if organized interests can identify the regulatory and economic mechanisms that inhibit innovation (Raven et al. 2016). This chapter suggests fossil fuel generation assets, energy costs, market concentration, and technical capacity pose barriers to various degrees, but these are surmountable in avenues outside of securing legislative control.

Conclusion

This chapter sought to test the theory of path dependence as it pertains to the decision making of public utility commissions. The guiding question of the project is whether regulatory and economic path dependencies work against adopting policies that expands distributed generation on the electric grid and the opportunities for behind-the-meter generation using renewable sources. While the previous chapter looked at the hold of political-economic factors on state-level policy more broadly, this chapter sought evidence of regulatory drift: that PUCs are reluctant to adopt pro-DG policies due to power system characteristics and the traditional utility business model of rate regulation. Across the data sample, however, we found that PUCs have generally been more favorable to DG access more often than they have rejected DG expansions, at least when examining the universe of agency rulemakings from 2012-2018. It should be pointed out that a more granular examination that places project approvals as the unit of analysis may show different trends. Policy drift can manifest as a systematic rejection of DG projects on an ad hoc basis. Similarly, PUC reticence toward DG may be made clear by analyzing the timeframe of PUC decision-making, such as whether the PUC votes to delay the consideration of an issue, or whether they punt to the legislature by claiming lack of jurisdiction. Future research should explore these avenues to garner a full illustration of regulatory drift in DG policy. The table below summarize the findings from this chapter's analysis of PUC decisions:

Table 4.8 Summary of Quantitative Results (PUC Decisions)

Independent Variable	Hypothesis	Result
Coal generation	PUC decisions in state-years with higher proportions of coal generation will be associated with higher probabilities for pro-DG decisions.	Reject null*
Elected vs. Appointed PUC	PUC decisions in states with elected commissioners will be associated with *lower* probabilities of pro-DG decisions.	Fail to reject
Distribution network capacity	PUC decisions in state-years with a greater number of distribution circuits per megawatt of generation capacity will be associated with *higher* probabilities for pro-DG decisions.	Reject null**
% Investor owned	PUC decisions in state-years with higher percentage of customers served by investor-owned utilities will be associated with lower probabilities for pro-DG decisions.	Fail to reject
Utility market concentration	PUCs in states with concentrated markets are more likely to favor DG access policy than PUCs in competitive markets.	Fail to reject
Regulatory policies scale	PUC decisions in state-years with a more robust utility regulatory regime will be more favorable to DG access.	Reject null†
Restructured market	PUCs in restructured states will be more likely to adopt policy advancing DG access.	Fail to reject
Partisan legislative control	PUC decisions in states with Democratic legislatures will be associated with *higher* probabilities of pro-DG decisions.	Reject null

* The significance of coal's impact on the likelihood of DG policy adoption is conditional by geographic region. Coal has the greatest impact in the Midwest, and a minimal impact in the South (see Figure 11).
** The significance of distribution capacity on the likelihood of DG policy adoption is conditioned by electricity price. Capacity has a stronger relationship with DG decisions in states with lower electricity prices (see Figure 12).
†The influence of energy/environmental regulatory regime on PUC decisions is conditional upon the degree of market concentration, with the regime bearing more heavily on PUC output in less concentrated markets (see Figure 9).

The analysis found that some factors result in PUCs behaving less favorably toward distributed generation policies.[104] A higher presence of coal generation in the electricity portfolio sways some PUCs away from adopting DG access policies, but the effect is only felt strongly in Midwestern states, while the effect is significantly weaker in other regions, particularly the South. PUCs in states with more concentrated markets – electric monopolies and duopolies – appear to favor utilities at the expense of new regulations that would expand the opportunities to

[104] See Chapter Five for an in-depth discussion and further analyses of the results.

deploy innovative technologies. Environmental and energy regulations are more likely to result in pro-DG policy outputs in more fragmented and diffuse electric markets, in which customers are served by numerous small electricity providers rather than large investor-owned utilities.

Other political-economic factors appear to weaken path dependencies. A strong regulatory framework is useful for increasing the probability that regulators favor expanded DG access, but this is only true for states with less concentrated markets. Expanded distribution capacity positively affects the likelihood in PUC decisions, especially in states with lower electricity costs. However, the strongest predictor of all the selected variables is the percent of state legislators that are Democrats. The efficacy of institutional design as an element of path dependence is inconclusive, as this study is unable to parse the influence of commissioner selection method from partisan composition of the legislature due to the sorting of observations along party lines; nearly all data points in the elected subgroup are concurrent with Republican legislatures.

While this chapter sheds a substantial amount of opacity in the political-economic factors associated with DG regulations, inferring the path of causality with a research design centered on PUC decisions is difficult. The multivariate analysis highlights several contours of the relationships that shape PUC decision-making regarding distributed generation policies, but the distribution of the data, the complicated nature of the policy network vested in electricity infrastructure, and the inherent constraints in identifying drift in a quantitative analysis leaves gaps in our knowledge about how internal machinations of utility commissions respond to external factors. The next and final chapter will consider further ramifications of the results from Chapters Three and Four, and then explore what elements might allow us to elucidate the shape of path dependency and regulatory drift in the DG policy process with greater clarity.

Chapter V

Researching the Political Economy of Distributed Generation and the Energy Transition

Introduction

This project has sought to answer the question of why states vary in their approaches to regulating the electricity sector; specifically, why some states are more resistant than others to adopt policies facilitating the integration of distributed generation technologies onto the power grid. Alternatively, we can conceptualize this question as what causes variation in state policy responses to climate risks. To answer this question, the project conducted an empirical study on the factors influencing policy change and stability in distributed generation to determine whether political resistance to DG grid integration can be explained as a product of regulatory and economic *path dependence*. The dissertation theorized that constraints produced by path dependence such as reliance on coal-fired generation and concentrated utility markets would manifest as *policy drift* as the electricity regulatory regime lagged behind an evolving social risk environment created by climate change. The lock-in produced by the centralized utility system creates resistance to integration of distributed resources and the shift toward an increasingly decentralized electricity infrastructure, highlighting simultaneously (a) the status-quo bias of regulatory institutions, and (b) the need for institutions to update regulatory frameworks to bolster risk protection regimes against climate risks. How do we make sense of the quantitative results of the preceding chapters? Did the findings provide clear answers to the above research questions and exemplify path dependence and regulatory drift in DG integration policy as hypothesized?

The simple answer is that some degree of path dependence and drift are apparent in DG policy, but the reality is complicated, and not all expected/theorized phenomena are evident in the data. The contributions of this research to our understanding of the institutional and economic constraints on change in public utility regulation are complex and multifaceted, but we are able to make qualified inferences given the project's findings. First, to address the literature on carbon lock-in, prevalence of coal generation in the electricity portfolio is not a monolithic constraint preventing the adoption of DG policy, though the prevalence of coal assets does dampen the probability of adopting comprehensive DG integration initiative. The observable market concentration in the utility sector does not largely impede DG integration; in fact, more concentrated markets appear *more favorable* toward DG integration than fragmented markets in the aggregate. Despite the hypothesis that natural monopolization inhibits technological progress, big utilities have acted as innovators and can effectively commercialize DG technologies. Additionally, they can potentially absorb the financial impacts of DG deployment without incurring adverse consequences relative to smaller utilities, striking a blow against the theory that path dependence, created by a centralized utility system, thwarts all attempts at DG integration which would accelerate decentralization.

Despite the findings counter to the theory as hypothesized, path dependence and policy drift in DG policy is more observable when considering the role of a state's regulatory regime and technical attributes. Having a previously-establish framework of regulations that constrain the utility sector's rate design and carbon emissions push decision makers to be more favorable toward DGs in less concentrated markets, and electricity prices together with developed hosting capacity lessen resistance to DG programs. It should be noted that partisanship explains a good deal of variation, but divided governments are almost as likely as Democratic governments to adopt DG integration policies. In sum, path dependence affects the DG policy environment, but in such a way that is highly conditional, and in certain respects, counter intuitive. Further research is needed to flesh out the dynamics of policy drift as driven by regulatory and economic path dependencies, but this dissertation has constructed a valuable starting point to carry out public policy and political economy research on the factors shaping power sector regulatory outcomes.

The final chapter is devoted to untangling the complexity of the information gathered and presented in this dissertation and to distilling its essential findings, with an emphasis on how researchers can investigate the dynamics of DG integration policy. First, I summarize the empirical findings of the quantitative analyses with a focus on their conditional nature and contributions to our understanding of the theoretical link between path dependence and policy drift in DG policy. Second, I suggest alternative designs and methodologies to improve upon the ability to draw causal inferences in this study, allowing for a more effective empirical verification of the theories of path dependence and policy drift in their characterization of regulatory change in the electric power sector. I conclude the chapter by discussing further avenues toward building a comprehensive research agenda to study policy change and the clean energy transition in the DG integration and power sector-relevant policies beyond distributed generation.

Verifying Path Dependence and Drift: Summarizing Findings & Contributions

The study found some support for the hypothesis that path dependence creates policy drift in DG integration policy, but the factors hypothesized to cause drift exhibit uneven effects across states. The percentage of coal-sourced generation and degree of utility monopolization appear to be significantly related to the favorability of a state's DG policy environment, but associations are conditioned by and interact with significant parameters, requiring careful and nuanced analysis. Additionally, not all relationships exhibited the expected direction, calling for a reconsideration of the role of path dependence and drift as theorized. Several aspects of the findings are worth reiterating.

Coal-sourced generation appears to exert a significant influence on the DG policy environment, as states with higher proportions of coal generation capacity are associated with less favorable policy environments for renewable distributed energy. However, on its own, this variable does not exert a great substantive effect; we must consider the interaction of coal generation with certain geographical factors. In the state-level DG policy index, electricity prices moderated the role of coal generation greatly. Higher proportions of coal generation did cause lower propensity for DG policy adoption, but this trend is clear *only* in states with higher electricity prices. States with higher electricity prices tend to be more urbanized, and many of these states have established complimentary policies such as energy efficiency standards and renewable portfolio standards, which would support DG deployment alongside integration policies such as net metering to reduce consumer bills. If a state does not have a policy regime designed to alleviate energy burden by creating a more efficient system, it is natural that the state would be hesitant to adopt DG integration policies, as the cross-subsidization that results from retail rate net metering presents an equitability problem. The ability for DG customers to circumvent grid charges effectively leaves non-DG customers to foot the bill of infrastructure costs. It should be noted that while evidence for net metering-driven cross-subsidization exists, the magnitude of the cost shift is negligible in utility systems with low net metering penetration levels, so we might conclude that resistance to DG integration could be a political calculation to avert financial risk to utilities, whereas less DG-resistant states incorporate assumptions of climate risks directly and thus display patterns of decision-making to proactively manage the technological transition to clean energy.

On the other side of the spectrum, in states with lower electricity prices, the ratio of coal-produced electricity is *positively related* to the policy environment for DGs, a result that somewhat muddies the theoretical explanation of path dependence and carbon-based technological lock-in. It could be the case that, as the proportion of coal electricity increases, the ratepayers' preferences for lower energy bills and the ability to generate and consume electricity autonomously from the utility grid strengthens, hence political support for net metering policies would not be dampened despite larger percentages of coal power. More research on ratepayer policy preferences and PUC receptivity to them is required to verify this speculation. I propose that we utilize a macro-level political-economic focus prior to diving into attitudinal and preferential research, because the positive relationship of coal power and DG in states with low electricity prices is explainable in part from the moderating geographical factors. The literature on carbon lock-in may seem to suggest economic ties to fossil fuel assets is an all-encompassing political force preventing the adoption of policy support for renewable energy, but the findings from this project suggest otherwise, as the impact of coal on DG policy environment is conditional upon several factors. While the isolated impact of coal assets on DG favorability in this data is somewhat ambiguous, what *is* certain is that specific geographical elements confound a straightforward coal-DG policy relation and must be taken into account.

For example, states with lower electricity prices and higher percentages of coal-fired electricity tend to fall either in the Western or Midwestern regions, both of which have frequency distributions that complicate a simple analysis of the DG favorability across states within each block. Summarizing the DG policy trend is especially problematic in western states for several reasons. The mean DG index score for Western states is slightly above the mean with a proportion of coal power close to southern states at about one-third total, yet the mean DG score for the South is much lower, a finding that undermines the carbon lock-in aspect of the path dependence theory. Western states on the upper end of scores exhibit very low amounts of coal generation and higher proportions of hydroelectricity. However, in a state like Colorado, which has minimal hydroelectric power and significant coal-sourced electricity, policymakers sought to improve DG access by adopting community solar and energy storage programs, calling into question whether path dependence creates policy drift in all cases.

Nevertheless, the prominence of coal in the generation portfolio does exert an impact on DG policy while controlling for the political environment, so the theory of carbon lock-in is not altogether disproven, but we must qualify the statement that heavy reliance on coal leads institutions away from technological progress. The aggregate analysis of PUC decisions found evidence that higher coal-sourced electricity does track with the hypothesized inverse direction of DG favorability in terms of the probability of major policy adoption, but only slightly in northeastern and western states, and even a slight positive relationship between coal and DG is present in southern states.

Several factors could be confounding the true relationship between coal power and DG favorability. Hydroelectricity on the west coast and in the Tennessee Valley Authority service area, the broad scope of census designations, the minimal variance of coal electricity across southern states, and political dynamics weaken the hold of coal assets on DG-relevant decision-making relative to other factors. In fact, regarding this last variable, partisan composition was found to be the most significant indicator in both quantitative chapters, further undermining the economic path dependence argument compared to the association of political conservatism with resistance to DG integration. However, since the quantitative models controlled for partisan composition of the state legislature, we can conclude that resource mix and availability bear on influence on policy output separate from the constraining effects of the broader political environment. Coal-sourced electricity plays a role independent of policies constraining DG policy adoption, but with the qualification that this effect is only prominent in Midwestern states. While drawing a parsimonious causal inference is improbable due to the nature of the data, especially its sparseness, we can conclude that carbon-based path dependence does *not* constrain states from advancing DG integration in a *prohibitive* sense.

To ascertain whether path dependence creates policy drift, a more valuable approach than an analytical lens of carbon lock-in would be to consider the influence of the regulatory environment holistically as a framework of constraints broadly affecting the probability of adopting pro-DG integration policies. I emphasize two regulatory factors and their associated interactions in exemplifying path dependence and policy drift in the utility sector. First, whether the state has a restructured or vertically integrated market plays a significant role in determining favorability towards DG integration, but not in isolation. The third chapter found significant interactions between coal mix and market type, with coal mix bearing more heavily on resistance to DG in restructured states. In vertically integrated states, coal generation exhibits a weaker negative association with DG policy environment, but one region – the Midwest – stood out as showing a slight positive relationship. Interestingly, this interaction is the *reverse* direction found in the fourth chapter: that across Midwestern states, PUCs were significantly less favorable toward DG given higher amounts of coal power. This contradictory finding tells us we should be hesitant to conclude that market restructuring can easily break fossil fuel-created path dependence in all regions, but if restructuring allows greater access to renewable energy, carbon lock-in may be weakened. The results also suggest that carbon lock-in and business model lock-in manifest as different phenomena and constrain policy outcomes to divergent degrees; coal assets may not be as important in determining DG resistance as centralized asset ownership generally.[105]

Second, a robust regulatory regime governing the utility sector is correlated with pro-DG outcomes, as states with portfolio standards, emissions standards, and revenue decoupling more likely to advance DG integration, as found in Chapter Four. On the other hand, in states with concentrated utility markets, the relationship shows the reverse direction: rollbacks and restrictions on DG access appear *more* likely alongside more robust regulatory regimes given a market environment with large IOUs, and major policy advancements are *less* likely with the increased stringency of utility regulations. Moreover, we must consider the potential contradictory findings between (a) the effects of the regulatory regime-market concentration interaction on PUC outcomes found in Chapter Four, and (b) the positive association of high market concentration with high DG index scores found in Chapter Three. Together, these results suggest the possibility that larger IOUs are more supportive of DG integration programs than smaller utilities, but simultaneously, major IOUs can be a stronger source of policy drift and more likely to attempt retrenchment and rollbacks in institutional venues.

What could explain the relationship between regulatory environment and probability of DG policy adoption and apparent contradiction in findings above? I first consider the dynamics in fragmented markets and propose that technical capacity and access to financial resources is

[105] This assertion is further supported by the modeling of the proportion of natural gas in the generation portfolio. After conducting several model iterations, there were no significant relationships between natural gas and DG policy favorability.

part of the answer. Large IOUs may have access to greater financial resources and have greater technical capacity to absorb and manage the effects of integrating distributed energy systems, whereas smaller utilities face tighter financial constraints and possibly operate with sparsely updated infrastructure, explaining how markets shaped by large IOUs. The lesser capacity to manage integration and modernize delivery systems potentially sways smaller rural utilities from promoting DG deployment as a precaution to avoid negative rate impacts such as cost-shifting. The data shows that the financial and technical concerns are substantially mitigated by an energy conservation-oriented regulatory framework that constrains utility behavior, supporting the policy drift model in DG policy. In fragmented markets, in which electricity customers are served in larger part by municipal utilities and cooperatives, and legislatures trend more Republican, regulatory frameworks push policymakers to facilitate greater adoption of innovative technologies. If *regulatory certainty* can be provided through policy frameworks that articulate objectives of clean energy and efficiency, actors are less likely to drift from pro-DG policy regardless of partisan affiliation.

The story appears differently in concentrated markets, in which large utilities may be supportive of incremental measures such as pilot programs and financing arrangements but less supportive of comprehensive policy change. Before proceeding, I offer a note of caution that rollbacks were the least frequent of all policy outcomes studied in the fourth chapter at roughly 10% of the dataset, so these speculations require further research with more comprehensive data for confident inferences. The positive relationship between rollbacks and regulatory regimes suggest that policy drift is more likely to occur in concentrated markets. Large investor-owned utilities carry more influence on decision-making due to their interactions with the PUC; a PUC would be more wary of major policy change opposed by a utility that serves a greater percentage of customers in the state. The risk aversion and status-quo bias would explain why a state might simultaneously have a robust regulatory regime and be resistant to DG policy. Because the regime would be established in statute and many aspects of DG integration would be devised by regulators, decision-making could drift from thorough implementation of energy policy goals, such as significantly reducing the compensation rates for net metered systems.

Opportunities for retrenchment are created when broad legislative discretion is provided to the regulatory agency to make policy changes. For example, Nevada is a heavily concentrated market in which two operating utilities – owned by the same holding corporation – control the vast majority of state market share. The case exemplified a scenario in which the legislature was receptive to a major IOU's efforts to roll back retail rate net metering, and they authorized the PUC to conduct a cost-benefit analysis and modify net metering tariffs without specification of the appropriate amounts or step-down schedule. The IOUs temporarily succeeded by dramatically cutting net excess generation compensation rates despite the state's recent history of progressively adopting more robust DG integration policies. The legislature was forced to reconsider its decision and provide clearer direction to the PUC on the development of a successor tariff to net metering due to the economic squeeze imposed on its rooftop solar market by recent policy changes. Absent clear policy direction to provide guidelines for moving beyond retail rate net metering, the PUC excessively favored IOU preferences at the expense of consumers and renewable energy companies, leading to policy drift. A series of regulatory decisions that hampered clean energy policy goals together with a legislature slow to update DG integration policies created an environment conducive to policy drift, as the PUC occupied a position of risk aversion, effectively abdicating implementation to the major IOUs.

Both the market structure and regulatory framework findings lend credence to the path dependence and regulatory drift models. While carbon lock-in is not evident a massive force of institutional inertia, the long standing regulatory compact and economics of utility infrastructure development do act as sources of technological path dependence. In some ways, fragmented markets seem to be more path dependent, likely because their revenue models are more vulnerable to the decentralization driven by DG adoption than IOUs with substantial consumer market share. Increasing grid capacity in fragmented markets reduces technological path dependence. Also, utility regulatory regimes lead fragmented markets to be more favorable to DG integration policies. Conversely, regulatory drift is more evident in states with concentrated utility markets because major utilities might seek marginal policy changes at the PUC to reduce adverse effects of DG integration without altering the overarching policy framework.

Methodological & Design Limitations

Essentially, this project was able to satisfy a few *necessary* conditions for the theories of path dependence and policy drift in the utility sector, but I caution against overly deterministic or confident reading of the results as it must be clarified that the conditions for *sufficiency* have not been totally satisfied. The ability to draw causal inferences is limited by a few significant factors, primarily data sparseness in certain variables and the issue of change over time. I will discuss each of these in turn and suggest two broad ways to improve upon and expand the research design carried out in this project: (1) expanded time scale and (2) increased granularity of the data.

First, the data collected over the 7-year period is useful for gleaning insights on aggregate-level dynamics of the political and economic factors affecting DG policy, providing a snapshot of the relationships we would expect to observe under the analytical frameworks of path dependence and regulatory drift. However, capturing the influence of certain factors on the favorability of the policy environment is made difficult by the sparseness of data, leaving us with inadequate tools to satisfactorily isolate the causal effects of political and geographic variables. For example, this project sought to determine whether institutional designs create meaningful constraints on policy adoption that would advance innovative technologies despite concerns over short-term financial risk. The fourth chapter modeled the influence of public utility commissioner selection method to determine whether elected or appointed PUCs were more likely to resist DG integration, but only roughly 10% of rulings in the dataset were delivered from elected PUCs, hampering the confidence of results. Additionally, excluding the partisan composition variable would lead to spurious conclusions on the influence of selection method on policy output, because the vast majority of elected PUC decision were made in predominantly Republican states. It is impossible to draw inferences on the causal relationship of institutional design independent of partisanship given this data.

It is worth considering whether the elected PUC-Republican correlation is itself a reflection of path dependence, as we could speculate that a conservative political environment may be more likely to reduce agency discretion. Diminished administrative authority raises institutional barriers to change in part because agents are driven in larger part by the preferences of political actors. Appointed PUCs may be more likely to incur short-term risk to satisfy long-term policy objectives, freeing them to assume the risk of adopting innovative technologies. Conversely, elected PUCs would be more bound to ratepayer preferences, who would largely reject the rate impacts associated with DG integration, especially retail rate net metering, in a state with conservative political attitudes. More research with complete data is needed to empirically verify these speculations, but much of the theoretical groundwork for answering these questions has been laid by this project and other researchers (Sautter and Twaite 2009).

The frequency distribution of the data also presents problems when attempting to interpret the role of geography as a moderating influence on policy outcome. This project conceptualized geography as a proxy for resource availability to determine whether economic variables such as proportion of coal generation affected policy favorability in different regions with different resource mixes. We can confidently say that the influence of coal power does exhibit different magnitudes in different regions, but illustrating the true relationship between coal power and DG policy faces complications. First, while intra-regional DG policies exhibit wide variance, intra-regional variance of coal-sourced electricity is much less in all but the West. Establishing causality in the Northeastern region is especially problematic because northeastern states are far less dependent on coal electricity due to the abundance of hydropower resources, making the confidence intervals for the coal-DG slope in the Northeast larger than is ideal for confirming causality. Moreover, the four census regions may encompass too much territory to serve as an effective proxy for resource mix. For example, the intermountain west and coastal states have divergent resource portfolios, with the west more reliant on hydropower and the mountain states more dependent on coal. Breaking the data into subregions may resolve this issue but including nine subregions overly complicates the quantitative models and spreads the data sample too thin to be amenable to multiple regression and maximum likelihood estimation analysis.

The data also inhibit our ability to sufficiently verify policy drift and path dependence due to the limited treatment of change over time. The data was collected over a 7-year period and specified random effects at the state level to account for unobserved heterogeneity across states.

While this method is useful for constraining model results spatially by treating states as panels, it is less useful for ascertaining influence of variables as values *change over time*, making it difficult to capture the temporally bound effects of institutional choices. Essentially, the empirical portion of the project provides a snapshot of the relationships we would expect to observe if the path dependence and policy drift models characterize policy change in the power sector, but further research must expand the time frame to sufficiently verify whether these theories meaningfully shape regulatory outcomes.

In light of these issues, I offer suggested improvements to the research design that would raise the confidence of results and improve on the project's ability to draw causal inferences. I propose two overall modifications to this research design to address the methodological limitations discussed. First, I propose more precise measures to capture the rate of variable changes over time to capture path dependence. Second, increased granularity of the data will provide a more complete picture of policy drift by illustrating the incremental changes at the implementation phase at a smaller scale.

Time-Sensitive Analysis

Regarding the treatment of the passage of time, successive research projects could utilize a variety of methodological tools to improve the ability to draw causal inferences derived from regulatory and economic path dependencies. The self-reinforcing mechanisms of network externalities, adaptive expectations, high fixed costs, and technological lock-in all imply that *temporal ordering* significantly constrains the range of policy outcomes. A more sufficient operationalization of path dependence would attempt to precisely measure the increasing returns yielded by conventional centralized power infrastructure, and how policy choices reflect each of the above self-reinforcing mechanisms. An approach that weighs the *increments* of variable changes and their effects on evolution of the policy environment is the natural next step for research studying the sources of change and stability in DG integration.

If we conceptualize path dependence as the constrained trajectory of potential policy decisions based on previous choices, we could develop an analytical model that traces policy developments back to the initial historical moments that were *formative* in shaping the prevailing arrangements characterizing electricity infrastructure. The Public Utilities Act of 1935 (PUA) and the Public Utilities Regulatory Policy Act of 1978 (PURPA) are such formative moments that were critical for determining the policy environment for state activity. The former placed retail utility markets under the jurisdiction of state regulators and the latter injected competition into monopolistic markets, allowing for greater deployment of innovative technologies. To understand the variation of state level distributed generation policy in the contemporary era, we would need to understand states' political and economic responses to these federally driven critical junctures when they occurred and over the course of time, as market dynamics and technical attributes would experience divergent trajectories across states given different starting points. It is feasible that a state which proactively sought to carry out the objectives of PURPA more thoroughly, via methods such as expediently approving solar power purchase agreements with reasonable contract terms, would be more supportive of integrating DGs in future decades.

This project captured some aspects of increasing returns by testing the association of coal generation and market concentration with the favorability toward DG integration, but a more complete model would utilize the *deltas* of each of these variables rather than mapping out the statistical correlations over a 7-year period using cross-sectional data in a multilevel hierarchical model. Measuring the annual changes in each variable would give us the means to analyze whether the *rate of change* in economic factors determines the degree of political resistance to DG policy. If increasing returns constrains policy outcomes favoring DG integration, perhaps a rapid decline in coal generation would make policymakers more amenable to DG adoption than a state in which assets provide a stable economic base. Alternatively, we could test whether the growth rates of DG penetration make states more likely to retrench or roll back DG integration programs. Since net metering results in cross-subsidizations with adverse ramifications for equity *only* in cases with high penetration levels, we can speculate on whether increasing returns and transaction costs obscures the long-term technical and social values delivered by DG integration to policymakers, inhibiting comprehensive policy change.

Time-sensitive variables provide the means to use sophisticated quantitative tools that lend greater veracity to the path dependence theory. Expanding the dataset to include datapoints at prior points in time allows us to move from cross-sectional format to utilize *time-series analysis*, which will allow us to treat the increments of change in economic indicators as causal factors independently from the political environment. In a time-series model, we could specify the differenced values of the coal-sourced generation, utility market share, and determine their correlation with DG policy changes as reflected in the DG index score. This is a necessary exercise in determining causality, as incorporating the differenced values allows us to determine how the influence of utility investments affects the propensity for DG policy favorability as time passes, giving us the means to infer the directionality and magnitude of relationship between coal generation, market concentration, and DG policy environment.

Such a design can better illustrate the lock-in effects of technological investments as they constrain future policy choices. For instance, decisions supporting legacy fossil fuel investments, such as adopting lax environmental standards for coal-based power plants, might be correlated with lower favorability toward DG integration. On the other hand, decisions protecting fossil fuel assets may be less likely if the investments were made at a later point in time, despite the prevalence of coal in the current generation mix. Additionally, we would need to compare the point in time that infrastructure investments were made with the *depreciation schedules* of assets; perhaps utilities are less resistant to technological change if assets are closer to their scheduled decommissioning date. Future research could examine DG policy outputs alongside the decommissioning schedules of all baseload resources, including coal and nuclear power. Furthermore, we could determine the influence of *economic perceptions* on policy outputs. Much political science research investigates the relationship between perceptions of economic health and public approval for specific policies; this research could examine the relationship between perceptions of the economic effects resulting from DG integration and public support for DG policies (Kellstedt and Whitten 2013).

Moreover, in examining the question of whether regulatory drift occurs across states, we can research the direction of policy outputs relative the state's established regulatory regime shaping power sector governance. While this project analyzed the relationship between utility regulations and favorability towards DG integration, future projects can determine whether drift is more or less likely to occur given the interaction of (a) time between critical policy developments and (b) economic factors such as reliance on coal generation and consolidation of utility market share. *Event history analysis* (EHA) can yield insights on whether the establishment of regulatory policies advances diffusion of DG policy options, or alternatively, what factors inhibit the adoption of DG integration, letting us determine whether certain factors cause variation in the *duration* of periods of policy stability. EHA allows for a more explicit treatment of *risk* as well; not only would we be able to infer the likelihood of policy adoption given a range of possible conditions, but we would be able to ascertain the risks presented to policymakers in causing a *non-adoption* policy output and maintenance of the status quo (Box-Steffensmeier and Jones 2004).

Hence, EHA can incisively capture the risk-aversion of utility regulators, and we could draw more confident conclusions on whether technological lock-in and network externalities inhibit policy adoption. If so, the increasing returns model would receive greater verification in the data, and we could illustrate a clearer link between path dependence and regulatory drift. An alternative design to this project might be to take an inventory of all net metering activity since PURPA, then (a) measure the units of time between DG policy changes, and (b) determine whether utility regulatory policies such as portfolio standards or revenue decoupling influence the duration of periods between policy changes. Drift would be evident in observations that exhibit longer durations between critical moments of DG policy change whilst having a somewhat robust regulatory framework, and we could conclude that economic path dependence is the cause if (a) the state's investments are predominantly geared toward fossil fuels, and (b) most electricity consumption is provided from centrally owned assets.

Exploring Different Levels of Analysis & Dependent Variables

Regarding the design issues presented by the level of analysis, increased granularity of the data could capture path dependence and drift more thoroughly, providing the means to identify the causal mechanisms affecting the DG policy environment. The issues presented by mapping out the geographical interactions could be solved by narrowing the unit of analysis from the state-level perspective. Utility-level or program-level analysis may be necessary to capture policy drift, as much PUC decision-making revolves around utility-specific considerations. While this project incorporates program-level decision making to an extent in Chapter Four by coding the approval or disapproval of certain utility distributed energy programs, we could disaggregate the data further by dividing independent variables into blocks for each utility's customer share. For example, the quantitative chapter modeled the *state average* electricity prices and portfolio mix but modeling the *utility average* customer bills and generation base would provide greater information and allow us to determine whether electric companies with greater resource access tend to secure more favorable decisions from PUCs in the approval of DG programs. A utility-level focus could yield more precise insights on the factors affecting regulatory decisions related to *fixed charges* or grid access fees on DG systems. For example, the Alabama Public Service Commission recently approved a rooftop solar charge increase by Alabama Power, while the Kansas Corporation Commission rejected an analogous increase proposed by Evergy (Lyman 2020, Wu 2021). Given the similar political environment, we might design an empirical study to research why these two states' regulatory agencies responded in opposite directions to a financial hindrance on DG deployment.

Selecting a different unit of analysis provides ample opportunities to consider the relevance of intergovernmental dynamics to policy drift theories. Local-level analysis might be able to probe into greater detail in verifying drift than state-level analysis because permitting processes are administered by local governments, giving us insight into whether implementation of clean energy policy objectives are thwarted by resistant municipal or county regulators. This project analyzes statewide interconnection standards as an indicator of DG policy environment, but we could narrow the dependent variable to examine the trends in regulatory approval for individual DG projects as well. Regulatory drift might be observable utilizing *permitting delays* as the dependent variable could prove to be an excellent indicator of drift; if DG projects never receive or are slow to receive approval for construction and interconnection, we can conclude that drift can occur in a framework of second-order federalism; implementing state-level objectives may encounter difficulties if regulatory barriers persist at the local level.

Similarly, we could examine project interconnection delays at the federal level by studying how administrators of national-level policy inhibits or facilitates widespread technology adoption, and by extension, pro-activity in updating risk protection regimes. Toward this goal, we could more closely examine the policy responses to PURPA and FERC rulemakings by states and regional transmission organizations (RTOs), which govern wholesale power markets. Regarding the former, the dissertation did include some PUC decisions relevant to power purchase agreements such as prices paid to independent power producers and term duration changes, but we could expand the dataset to analyze the series of renewable contracts approved by utilities to properly illustrate the policy environment as driven by utility investment decisions. Regarding the latter, FERC established two rules significant for DG grid access in recent years. Adopted in 2018, Order 841 lowered barriers for energy storage projects to participate in RTO markets, and FERC Order 2222 of 2020 required RTOs to allow wholesale market participation of distributed energy resource (DER) aggregators (FERC 2018, FERC 2020). Order 2222 means that service can aggregate the demand across multiple DER facilities, including "electric storage, distributed generation, demand response, energy efficiency, thermal storage and electric vehicles and their charging equipment," allowing such projects to compete against conventional energy sources (FERC 2020).

The pace and rigor that RTOs will apply to administering the DER and storage orders remains to be seen, as the implementation process is still in nascent stages. It is feasible that RTOs might be slow to approve integration of DER aggregators because there is evidence that permitting delays occur with large-scale resources. For example, PJM had forced renewable developers to request a three-year extension for installing a 46 MW solar project because the RTO had required a re-evaluation of the interconnection study based on concerns over inadequate transmission capacity (Morehouse 2021a). The delay had contributed to state regulators' consideration of withdrawing from the regional capacity market altogether to better fulfill Maryland's clean energy policy goals. In addition to the recent FERC orders, the appointment of a Democratic chairman in the Biden Administration has allowed FERC to examine PURPA modifications that would significantly boost deployment of solar generation systems (Morehouse 2021b). Considering the suite of reform-oriented activity at the federal level, it is worth exploring whether subnational governments and pace RTOs are fulfilling the policy objective of increased DG project deployment. If states, localities, and RTOs tend to maintain regulatory barriers militating against technological change, we might consider that financial and political risk aversion leads infrastructure to greater exposure to climate risks.

Independent Variable Alternatives to Coal Generation

Path dependence is measurable via other means than the variables employed in this study. The carbon lock-in thesis might find greater support if we look to indicators other than the proportion of coal in the electricity mix. Coal generation may be an imperfect proxy for reliance on coal, as the political resistance to switch to renewables may be a direction function of the financial streams provided by coal assets. This project couched the policy problem of DG integration in the concerns of cost-shifting and cross-subsidization, justifying the selection of the generation-proportion variable in analyzing path dependence, but it could be the case that policymakers are more reticent toward DGs due to the *workforce impacts* resulting from the clean energy transition rather than cost-shifting. As renewable technologies are deployed at higher rates, the risks to power plant communities raises with the threat of closures, spurring policymakers to resist the encroachment of innovative technologies on legacy assets. We might estimate the association of number of active mines or the proportion of conventional fuel workers with anti-DG policy outcomes to further explore whether path dependence creates resistance to DG programs.

Additionally, states might be locked-in to fossil fuel assets not because they are reliant on coal or gas-fired generation for electricity supply, but because state budgets are locked-into *severance tax structures*, making them dependent upon fossil fuels. Examining whether severance taxes constrain states' propensity to enable DG policy entails a substantially different focus than the utility-focused analysis as employed in this study, as fossil fuel excavation occupies an altogether separate segment of the supply chain than electricity production and does not fall under the regulatory purview of public utility commissions. Nevertheless, it is worth considering whether the state's economic base weighs on the legislative environment for renewable energy technologies. While modeling workforce or severance tax revenues alongside percentage of coal generation would introduce problems of multicollinearity in this dissertation, future studies can investigate the quantitative effects of these variables on the state's favorability toward DGs, providing a clearer portrait of path dependence and drift as they constrain advancement on DG policy.

We might consider methods to test states' technological lock-in beyond coal, by examining the effects of the *utility business model* on policy outputs more broadly. This project used coal, along with market concentration, as an indicator for the centralization of the utility system, but we could explore the relationship between lock-in and DG policy outcome by examining the relationship between a state's *nuclear portfolio* and DG regulations. Utilities that are heavily reliant on nuclear may be more restrictive of the amount of DGs allowed onto their system. Future research can determine whether a nuclear-heavy generation mix works against state efforts to increase DG access.

This project has taken the necessary step in laying the theoretical and empirical foundation for verifying path dependence and drift in DG policy by exploring whether the expected political-economic relationships suggested by the theories bear out in reality. The proposals discussed above to (a) expand the time scale and (b) narrow the unit of analysis would further contribute to our understanding of regulatory drift in the power sector by building on in an intergovernmental context, effectively building on this dissertation's findings. Regulatory drift is caused by a range of procedural mechanisms and occurs at multiple scales, hence illustrating a complete portrait of drift would require mapping out the institutional links and universe of political-economic incentives constraining decision-making in DG policy. The cross-sectional multilevel model design utilized in this correlational study can be expanded to address intergovernmental dynamics and incorporate the strong temporal element implicated by path dependence theory (Gellman and Hill 2007). An analysis with heightened sensitivity to change over time combined with precise measures of policy activity in DG integration, a time-series or event-history analysis would prove a natural next step in exploring causal pathways influencing the DG policy environment and likelihood of comprehensive policy change.

Successive Research: Future Study on DG Policy and the Energy Transition

I conclude the dissertation by offering several avenues of future research topics for studying the sources of policy stability and change in DG policy and power sector regulation more broadly.

The theoretical and practical contributions from studying the transition are manifest. For policy analysts and practitioners, there is a critical need to understand the causes inertia exhibited in power sector regulation. For social scientists and public policy research, the causes and extent of regulatory drift in power sector regulation is an understudied area. In this section, I lay out a research agenda to expand upon literature examining policy change and power sector regulation relevant to clean energy and climate policy in two broad categories: (1) deeper qualitative and observational analysis of state-level regulatory drift, and (2) examining policy developments around clean energy technologies beyond distributed generation, specifically distributed energy resources and regionally coordinated resource planning.

Capturing Causality: Moving from the Aggregate-Level

Research designs that would depart from the cross-sectional correlational methods utilized in this project could provide greater ability to infer the causal mechanisms of policy change and stability in DG integration. In its focus on the aggregate, this dissertation serves a vital function in providing a baseline of external validity to complement more descriptive and observational studies. Several avenues are available to researchers that could provide more robust observations of the dynamics constraining state policymakers from aggressively supporting DG policies.

First, I propose researchers develop methods to build a *natural experiment* to investigate the causal factors of favorability toward DG integration policy. Natural experiments are quasi-experimental in that they treat the values of independent variables as if they were random, which is useful for conducting research in which random assignment is impossible in practice (Kellstedt and Whitten 2013). It is impossible to randomly assign values of the independent variable in studying historical changes in the political-economic environment within states, but we can ascertain whether an instrumental variable creates variation along the values of a dependent variable whilst controlling for other potential causal factors via case sampling and variable selection. While randomness is not specifically present in natural experiments, sound design allows us to treat variation as if it occurs randomly with the caveat that variables emerge "naturally" as a product of institutional, geographic, and economic factors and are not *actually* random, hence analytical and modeling choices must be theoretically justified in order to isolate the causal effects driven by the primary independent variable(s) of interest. Natural experiments are useful tools for cross-sectional observational studies of aggregated clusters such as governmental units, hence the method is ubiquitous in political science (Kellstedt and Whitten 2013, Posner 2004, Stokes 2016). Natural experiments may appear to cut against the temporality and historicity inherent in path dependence theory, but due to the strong stochastic element that initiates divergent trajectories of increasing returns, natural-experimental observation studies are compatible with and contribute to path dependence models of social phenomena.

In designing a natural experiment to investigate the causes of variation in DG policy environment across states, we would select a subset of states that exhibit many similar political-economic characteristics. Natural experiments provide the means to carry out comparative public policy analysis, allowing us to test whether "random" variation in an instrumental factor causes divergent outcomes in political favorability toward DG integration. To build on the theoretical development in this dissertation, we might begin to constrain the universe of data by selecting states within the same region with similar electric resource portfolios to determine the cause of variation in DG policy adoption.

For example, Colorado and New Mexico have near-identical generation portfolios, yet policy activity in New Mexico was more limited and the DG policy environment more stable in the 2012-2018 timeframe, whereas Colorado pursued community solar, energy storage, and other initiatives in the same period. A natural experiment might test the *changes in resource mix* and *utility market share* changes as "random" independent variables impacting the DG policy outcome; despite the *average* in generation mix, annual changes in resource mix might move at a more rapid pace in Colorado, or alternatively, changes to utility revenues might create different political incentives to maintain the status quo across the two states.

Additionally, we could advance natural experiment designs to conduct inter-regional comparisons. For instance, given similar political compositions in each state, we could thoroughly tease out the causes for why the regulatory commissions of a Midwestern state – Kansas – and a Southern state - Alabama - responded divergently to utility proposals to increase DG fixed charges. Why the former rejected charges and the latter approved them is worth subjecting to observational experimentation and would give us greater ability to infer the causal mechanisms of variation in DG policy environment. The "random" elements causing variation in this case could be the heavy investments in wind generation in Kansas, potentially blunting the KCC's resistance toward renewable projects through its provision of regulatory and financial certainty to public and private actors. Alternatively, we could consider whether the regulatory regime is influenced by the characteristics of the utility market; while both states are vertically integrated and served by major investor-owned companies, a single utility – Alabama Power – provides electricity to the majority of customers in Alabama, raising the question of whether market consolidation materializes as political influence in regulatory decision-making and is the cause of the divergent policy outputs.

Aside from natural experiments, there is opportunity to delve into thicker description to clarify the political and economic constrains shaping the policy process revolving around DG integration. Historical analysis of a single agency or comparative case studies across a select few states would sufficiently bolster the theoretical underpinnings for explaining the drivers in determining observable policy actions, which is especially useful for understanding how regulatory regimes change over time. Following Eisner (1993: 15), “the most relevant level of analysis for regulatory studies is the individual agency.” Administrators are tasked with articulating the goals established in legislation, which outlines the regulatory charge to be carried out, and agents must be cognizant of the political, economic, and technical constraints facing them to do so. Therefore, an analytical lens that is sensitive to the temporality and sequential nature of public policy is needed to capture the constraining effects of previous decisions on future actions. Historical institutional analysis allows us to trace the process within a single agency to map out the causes of regulatory outcomes, an approach that is especially useful for illustrating the role certain political-economic factors play in actions related to utilities' distributed energy programs.

In a case study, we could take a comprehensive inventory of activities to observe policy changes in DG integration, such as (a) DG projects and programs proposed by utilities for PUC approval, (b) the upgrades to grid infrastructure in integrated resource plans (IRPs) to enable greater DG deployment, or (c) proposed rate structures or charges levied on distributed systems. A comparative case study would allow us to compare the effects of different political-economic environments on the probability that above DG options are approved. For instance, we could compare the resource planning procedures between Colorado and New Mexico over a 20-year period to determine what factors initiated greater policy activity towards later years in the time interval. Perhaps concerns over lost tax revenue resulting from plant closures are more prominent in New Mexico, therefore policy drift is more evident in the data as the regulatory environment is characterized by greater stability over time. Moreover, qualitative analyses allow us to probe the influence of interest groups on DG-related PUC decision-making more thoroughly, as other research has done on PUCs and climate policy (Stokes 2020, Brown 2017). Qualitative research may be better equipped to make declarations on whether industry capture shapes utility commission behavior, a question this dissertation has put aside. The natural experiment and case study approaches discussed here offer the ability to more thoroughly capture the time-sensitivity implied by path dependence and regulatory drift.

Research Beyond Distributed Generation: DERs and Regulatory Reform

Illustrating the path dependence of electricity regulation and policy drift related to clean energy and climate change requires analyzing policies and technologies beyond distributed generation. This project focused on DG because of the financial implications resulting from DG integration. As more DGs are interconnected and self-generation becomes more prominent, the risks of cross-subsidization and lost utility revenue weigh more heavily on decisions that would facilitate DG adoption, highlighting the issues with the long-standing utility regulatory compact and conventional business model. We can consider the influence of path dependence and dynamics of policy drift in other innovative technologies as well, because the clean energy transition and emergent climate risks calls into question whether prevalent power infrastructure governance is capable of reorganization into adequate risk protection frameworks and whether the political-economic environment enables policymakers to enact comprehensive change. The findings in this project suggest that incremental adjustments to electricity regulatory regimes are possible, but greater DG adoption alone is insufficient for mitigating climate risks. DG integration must be considered as one prong in a suite of policy actions to reorient the power sector around effective climate protection, which may involve dramatic transformations to uproot historically inert regulatory processes and business models. This section considers several clean energy policies alongside DG integration to contribute to our understanding of path dependence and policy drift in the power sector.

Expanding the analyses carried out in this project from DG to the broader category of *distributed energy resources* (DERs) would extend our investigation of technologies transforming the utility system. Mentioned above in FERC Order 2222, DERs include not only on-site generation, but also any technology that is located "behind the meter" and on the distribution network that provides value to the grid in terms of electricity supply or demand management capabilities.

Energy efficiency measures such as *demand response* programs are DERs that allow for management and reduction of electricity consumption. Demand response requires grid upgrades that allow for flexible management of the power supply and interoperability between distribution assets. For example, the installation of advanced metering infrastructure (AMI), or "smart meters," enables demand response by precisely measuring and controlling the flow of electricity to end uses and can provide utility in launching a variety of efficiency and load management programs. In times of peak demand, such as extreme weather events, demand response allows utility operators to modulate the amount of energy consumed to reduce the burden on the energy system. Participating customers would be reimbursed for reducing their usage, incentivizing the objectives of conservation and system reliability (Budhiraja 2019). Energy conservation policies should take priority in studying methods to reduce climate risk from the power sector, because lowering energy burden and improving the efficiency of the distribution system would provide greater resilience to climate events such as the 2021 Texas winter outages.

Similar to focus on DGs, an analysis of the factors influencing institutional resistance or policy change regarding action around energy conservation mechanisms allows us to test whether the conventional utility business model that incentivizes volumetric sales and infrastructure investments significantly inhibits adoption of energy efficiency regulations. Path dependence theory suggests that policymakers are faced with incentives to maintain the existing model of rate-regulation to maintain prevalent pathways of increasing returns, but efficiency standards would cut into utility revenue under the conventional framework. Many states have explored revenue decoupling, alternative rate designs, lost margin adjustment mechanisms, fuel adjustment charges, and other tools to address the financial ramifications of adopting comprehensive efficiency programs (Lazar et al. 2016). To apply a policy drift framework to studying changes in energy efficiency policies, we may examine whether regulatory decisions either punted on opportunities to adopt revenue adjustment mechanisms or failed to regularly update efficiency standards to increase system resilience. If we can attribute market consolidation and concerns over lost revenue as significant factors causing policy drift in efficiency goals, we can conclude that institutional path dependencies undergird the power sector's regulatory process.

Analyzing the favorability of policy environment for advancing DERs is essential for understanding the ability of regulatory regimes to adapt to new risk protection frameworks. Several technologies can be considered as tools to enhance the resilience and reliability of the power grid. First, we can analyze the political-economic factors associated with the propensity for weatherization programs, which seek to insulate customers and electricity infrastructure from extreme weather conditions for the enhancement of social well-being and system reliability. Analysts suggest that weatherization measures, due to the associated costs of initial implementation and lack of coordinated standards, were shunned by Texas utilities and the PUC, hence infrastructure assets were left vulnerable to the polar vortex of February 2021 (Ramsey 2021). The frequency of regulatory approvals for weatherization and the amount of funding devoted to such programs is a ripe area for study.

Second, we might narrow the analysis of a state's political environment's favorability toward DG. We could focus on a particular technology, such as *microgrids*, which involve distributed generation systems paired with battery storage, and research the question of whether regulators balk at efforts to deploy microgrids at greater scale due to the financial impacts for utilities. California policymakers are on the forefront of microgrid-related policy activity and have directed utilities to deploy microgrid technology to mitigate wildfire risks (Silverstein 2020). Because microgrids are less grid-reliant due to the pairing with battery storage, we can speculate whether political resistance toward microgrids is greater than standard DG programs such as net metering.

Third, we can study policy tools to encourage deployment of DERs statewide. The factors affecting the probability of adoption and rigor of implementation for two closely related policies can be studied: (1) business model reforms such as performance-based regulatory frameworks, and (2) integrated distribution planning. Neither are amenable to quantitative analysis because the policies are innovative and in nascent stages in a small number of states, but we can use descriptive analysis to examine the states that are pursuing them to ascertain the conditions amenable for significant policy change. Generally, the states that have made progress in developing one of these policy areas have pursued the other in tandem.

New York's Value of DER (VDER) tariff is one exemplar of business model reform and compensates DER projects for several benefits provided to the grid, including the energy value, capacity value, environmental value, demand reduction value, and locational system relief value (NYSERDA, n.d.). Essentially, DER projects receive compensation for reducing burden on the power system and is meant to eventually replace retail rate net metering. The VDER is the subject of an ongoing regulatory proceeding initiated by the Governor's Reforming Energy Vision initiative and led by the state Public Service Commission and the New York State Energy Research and Development Authority in consultation with stakeholder groups. Researchers can examine the VDER as a case study in business model reform, and we can examine and compare New York's process against Minnesota's Value of Solar Tariff (VOST) process, which has been slower to implement the tariff; no major implementation actions have advanced since the Minnesota PUC approved the tariff in 2014.[106] In fact, the Minnesota PUC approved a value of solar rate for Xcel community solar gardens significantly lower than the rate set by the VOST due to cost-shifting concerns driven by high program uptake.[107] This project included both states' policy changes in the DG index because they incorporate successor tariffs to net metering, but we might focus our institutional analysis on the few states exploring performance-based regulation or business model reforms whilst exploring the favorability of the political-economic environment toward technologies beyond distributed generation such as energy efficiency and smart grid projects. Policy analysts may study the extent to which regulatory reforms result in energy conservation, cost savings, and greater deployment of DER technologies.

Integrated distribution planning (IDP) is generally conceived as an addendum to utilities' integrated resource plans and requires the inclusion of planning for and coordination of DER integration into the wider power system. Several states are investigating or in the process of implementing IDP requirements, while five – New York, Minnesota, California, Nevada, Hawaii

[106] Minnesota Public Utilities Commission, Docket No. E-002/M-14-65
[107] Minnesota Public Utilities Commission, Docket No. E-002/M-13-867

– have already established them (Cutler and Chew 2020). IDP requirements share common elements across states, though not every state with IDPs have adopted all of these provisions: (1) utilities must develop long-term distribution or grid modernization plans, (2) requirement that utilities consider non-wires alternatives (to generation and delivery infrastructure) when making procurement decisions, (3) utilities must conduct hosting capacity analysis to determine technical feasibility of integrating DERs, (4) assessment of locational net benefits for siting/installing projects, (5) addition of "storm hardening" requirements for utilities to adopt resilience measures to protect infrastructure against weather events, and many others (Homer et al. 2017). Additionally, projects may not impose an unreasonable cost burden on ratepayers, a concern that likely stymies some states from engaging in grid modernization, though studies demonstrate that IDP upgrades can result in long-term cost savings for consumers and utilities (Frick et al. 2021).

Future political science research can examine more closely the institutional constraints preventing state policymakers from supporting grid modernization programs such as IDP requirements. This project's findings suggest the possibility that, in more fragmented markets, utilities with a smaller percentage of market share may be less willing to engage in grid modernization, possibly a smaller customer base leaves the utility less capable of absorbing the adverse financial impacts of high DG penetration levels. Upgraded grids lead utilities to be more amenable to DG integration programs, so it is worth considering whether substantial public investment is needed to boost DG deployment in states whose ratepayers are more reliant on public power entities and electric cooperatives, though DERs yield greater benefit in urban, highly dense networks.

Achieving Large-Scale Transformation

As a final point, it is crucial to acknowledge that DG/DER/efficiency is insufficient for totally mitigating the risks presented by climate change, and centralized utility-scale renewable energy facilities will play a major role in moving the power grid away from fossil fuels (St. John 2021). To complete the transition toward clean energy and achieve net zero carbon emissions from the electric power sector, two key policies must gain traction at the national level: *transmission build-out* to support utility-scale renewables and *integrating the US bulk power system*.

The lack of high-voltage transmission capacity is considered a major barrier to constructing new large-scale wind farms and solar arrays by grid analysts and renewable energy advocates (SEIA n.d., Wolf 2014). The regulatory process for approving construction of new transmission lines takes several years, involving the acquisition of rights of way, federal easements, and economic and environmental impact analyses. Additionally, most transmission planning occurs on an isolated jurisdictional basis, yet renewable-sourced electricity would need to be delivered across state lines, further complicating the siting/permitting process, and highlighting the need for regional coordination in resource planning. These jurisdictional and geographic constraints have locked renewable developers from constructing projects in resource-abundant regions and explains in part the exceedingly slow pace of regulatory approval for project such as Wyoming's 730-mile, 3-gigawatt TransWest Express project, which runs from the southwestern part of the state through Colorado and Utah to deliver wind power to the West Coast (St. John 2019). Hence, path dependence characterizes the electric grid's transmission system aptly; the cost of modernizing the balkanized system is prohibitively high due to the increasing returns associated with the initial investment in regional electric delivery infrastructure.

The degree of attention policymakers pay to untangling these regulatory barriers warrants research by social scientists; we might pose the question: what factors inhibit political actors from devoting resources to updating infrastructure regulations to address present needs? This project has suggested that path dependence explains a good deal of policy stability; perhaps utility and PUC reticence toward transforming the energy system based on lost revenue concerns militates against the comprehensive policy change. Given the slow pace at which state regulators pursue transmission to support renewable technology adoption, we might characterize the policy process as heavily weighed by regulatory drift.

The need for regional-level coordination to accelerate transmission planning points to another barrier in systemwide decarbonization: the outdated balkanized electricity grid, in which the US is divided into three major interconnections: East, West, and the Electric Reliability Council of Texas (ERCOT). Transmitting electricity across the interconnections is prohibitively costly, and research by the National Renewable Energy Laboratory demonstrates that integrating the three power grids would significantly reduce costs in the long-run and allow for inter-regional transfer of renewable-sourced electricity (Bloom et al. 2020). The interstate transmission of renewables is critical for achieving systemwide clean energy goals due to the intermittency of renewable resources; Midwestern wind projects would be able to provide electricity to Western states if sunshine is inadequate to meet demand on certain days, while Southwestern solar facilities could provide electricity to other regions on days with insufficient wind generation (WIRES 2020, Wind Energy Foundation 2018). Additionally, integrated national markets would make utility systems more resilient to extreme weather events; if winter freezes trip generators offline in a particular geographic region, the utility would be able to purchase electricity from an unaffected region.

Research on the political will to advance the bulk power system integration and large-scale transmission planning would complement this project's focus on DG policy. The outdated balkanization can be considered evidence of drift, as evolving conditions demand that intra- and inter-regional energy trade be made possible. These policy areas involve high fixed costs and prevalent network externalities, making them amenable to analysis under the path dependence theoretical framework. The isolated and myopic nature of retail-level utility resource planning may mean that path dependence is a stronger force in transmission and utility-scale projects than DG policy. I leave it to future research to set out in answering these questions.

Conclusion

Despite the gravitational hold that path dependence exerts on institutional decisions and the resultant tendency toward regulatory drift, contemporary discussions surrounding US energy supply and the future shape of the utility system demonstrate that technological innovation and transformative change is possible, even if that change proceeds incrementally. The pace of change can be a source of frustration to groups concerned about the scope of present and imminent climate risks, but there is cause for optimism in the pursuit of economywide decarbonization in current political conditions. With the proposed infrastructure package from the Biden Administration and the creation of the White House Office of Domestic Climate Policy, the objective to shift away from fossil fuels toward clean energy has never taken higher priority at the national level. At the center of the $2.3 trillion infrastructure plan is the goal to achieve a carbon-free electricity supply by 2035, a more stringent goal than any state-level clean energy standard passed to date ("Fact Sheet: The American Jobs Plan" 2021). As of this writing, many details of the plan are yet to be articulated by the White House and Congress, but the heightened agenda status of electricity sector decarbonization offers the promise of national coordination and substantial increases in public investment toward renewable energy technologies, possibly easing the economic burden and political resistance of widespread renewable energy among state policymakers.

However, we must be cautious in our optimism, as the path dependence and policy drift theories explain that adherence to long-standing institutional constructs tends to persist despite evolving social risks and shifting policy environment. While the establishment of new policy objectives is possible at one level, molding the trajectory of regulation to sufficiently achieve policy goals is made difficult by the incentives facing actors to preserve existing political-economic arrangements, and institutions tend to drift away from the objectives of risk protection entrusted to them. Transaction costs, technological lock-in, and increasing returns are concepts that illustrate the inertia of institutions and risk-aversion of political actors; because technological change would squeeze the returns provided by the prevalent system and technological base, innovative options are met with resistance, leading transaction costs to militate against rapid comprehensive change. Thus, decentralization and decarbonization of the power system has been met with political resistance, but signs of incremental progress at the state-level are evident regardless.

This dissertation has shown that the interconnection and compensation of distributed generation systems illustrates the path dependence and regulatory drift characteristic of electric infrastructure; cross-subsidization/cost-shifting is created by DGs as an artifact of the long-standing regulatory construct of rate-of-return utility regulation, which overvalues building assets and selling power at the expense of other values. The changing risk environment due to climate change and the availability of innovative renewable technologies begs the question of whether the old regulatory model is appropriate for the present era. Newer regulatory models that properly align economic incentives with the values needed for adequate risk protection – chiefly resilience, reliability, reduced emissions, and reduced energy system burden - would resolve the cost-shifting issues revolving around DG integration. However, conventional regulatory frameworks do not altogether incentivize progress in achieve these values, as they contradict the rate structure enshrining in centralized utility planning. The incoherence and price inefficiency of interconnecting DG/DERs into wider conventional infrastructure has led some policymakers to balk at DG integration, but the fact that some states are leading the charge on regulatory reform and reorienting the value stream to recognize the attributes provided by DGs demonstrates that the creation of risk protection regimes are possible even in concentrated utility markets. Policy diffusion scholars could investigate whether leader states can provide an example to other states figuring out how to cost effectively deploy distributed energy systems while minimizing negative impacts to ratepayers and utilities.

The path dependence and policy drift models employed in this dissertation demonstrate that institutional resistance might be overcome given the right political-economic conditions. The falling costs of renewable technologies, the provision of regulatory certainty, and modernization of grid infrastructure appears to effectively reduce institutional resistance toward DG integration, though the analysis shows that regulatory institutions generally tend to allow for incremental extensions of DG programs when they feel they are able, at least in the aggregate level. Forthcoming national-level policy changes may reduce institutional resistance to DGs and renewable energy even further. This project is less equipped to confidently conclude why individual states contract DG-supportive regimes once established, but future research can examine the cases of rollback and retrenchment more thoroughly to describe the political dynamics affecting such cases. With the next phase of systemwide transformation looming with unprecedented federal action, there is no shortage of avenues to advance our knowledge of the political-economic dynamics shaping institutional and intergovernmental responses to the clean energy transition.

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Appendix A – Distributed Generation Policy Index Data

DG Policy Index – State Scores

State	Year	DG Score	State	Year	DG Score	State	Year	DG Score
Alabama	2012	6	Delaware	2012	25	Iowa	2012	21
Alabama	2013	5	Delaware	2013	25	Iowa	2013	23
Alabama	2014	4	Delaware	2014	25	Iowa	2014	24
Alabama	2015	3	Delaware	2015	25	Iowa	2015	26
Alabama	2016	3	Delaware	2016	25	Iowa	2016	26
Alabama	2017	3	Delaware	2017	25	Iowa	2017	25
Alabama	2018	3	Delaware	2018	26	Iowa	2018	23
Arizona	2012	24	Florida	2012	21	Kansas	2012	13
Arizona	2013	23	Florida	2013	24	Kansas	2013	13
Arizona	2014	26	Florida	2014	24	Kansas	2014	12
Arizona	2015	26	Florida	2015	24	Kansas	2015	8
Arizona	2016	23	Florida	2016	24	Kansas	2016	8
Arizona	2017	23	Florida	2017	25	Kansas	2017	8
Arizona	2018	23	Florida	2018	25	Kansas	2018	8
Arkansas	2012	13	Georgia	2012	10	Kentucky	2012	11
Arkansas	2013	16	Georgia	2013	11	Kentucky	2013	11
Arkansas	2014	16	Georgia	2014	11	Kentucky	2014	11
Arkansas	2015	19	Georgia	2015	14	Kentucky	2015	12
Arkansas	2016	19	Georgia	2016	14	Kentucky	2016	12
Arkansas	2017	19	Georgia	2017	15	Kentucky	2017	12
Arkansas	2018	19	Georgia	2018	15	Kentucky	2018	12
California	2012	31	Idaho	2012	8	Louisiana	2012	12
California	2013	34	Idaho	2013	8	Louisiana	2013	11
California	2014	35	Idaho	2014	8	Louisiana	2014	11
California	2015	36	Idaho	2015	8	Louisiana	2015	10
California	2016	42	Idaho	2016	8	Louisiana	2016	10
California	2017	49	Idaho	2017	8	Louisiana	2017	9
California	2018	50	Idaho	2018	8	Louisiana	2018	9
Colorado	2012	29	Illinois	2012	28	Maine	2012	25
Colorado	2013	29	Illinois	2013	27	Maine	2013	26
Colorado	2014	30	Illinois	2014	27	Maine	2014	27
Colorado	2015	34	Illinois	2015	27	Maine	2015	29
Colorado	2016	34	Illinois	2016	32	Maine	2016	31
Colorado	2017	36	Illinois	2017	32	Maine	2017	30
Colorado	2018	37	Illinois	2018	32	Maine	2018	31
Connecticut	2012	23	Indiana	2012	22	Maryland	2012	26
Connecticut	2013	30	Indiana	2013	23	Maryland	2013	27
Connecticut	2014	31	Indiana	2014	24	Maryland	2014	30
Connecticut	2015	35	Indiana	2015	23	Maryland	2015	32
Connecticut	2016	39	Indiana	2016	23	Maryland	2016	34
Connecticut	2017	42	Indiana	2017	19	Maryland	2017	37
Connecticut	2018	43	Indiana	2018	19	Maryland	2018	37

State	Year	DG Score	State	Year	DG Score	State	Year	DG Score
Massachusetts	2012	30	Nevada	2012	23	Oklahoma	2012	12
Massachusetts	2013	31	Nevada	2013	24	Oklahoma	2013	15
Massachusetts	2014	33	Nevada	2014	24	Oklahoma	2014	14
Massachusetts	2015	34	Nevada	2015	21	Oklahoma	2015	13
Massachusetts	2016	36	Nevada	2016	21	Oklahoma	2016	13
Massachusetts	2017	36	Nevada	2017	26	Oklahoma	2017	10
Massachusetts	2018	36	Nevada	2018	26	Oklahoma	2018	8
Michigan	2012	21	New Hampshire	2012	20	Oregon	2012	28
Michigan	2013	21	New Hampshire	2013	25	Oregon	2013	30
Michigan	2014	22	New Hampshire	2014	25	Oregon	2014	32
Michigan	2015	22	New Hampshire	2015	25	Oregon	2015	33
Michigan	2016	25	New Hampshire	2016	25	Oregon	2016	37
Michigan	2017	25	New Hampshire	2017	25	Oregon	2017	40
Michigan	2018	25	New Hampshire	2018	27	Oregon	2018	40
Minnesota	2012	17	New Jersey	2012	22	Pennsylvania	2012	25
Minnesota	2013	23	New Jersey	2013	22	Pennsylvania	2013	27
Minnesota	2014	24	New Jersey	2014	22	Pennsylvania	2014	27
Minnesota	2015	25	New Jersey	2015	24	Pennsylvania	2015	27
Minnesota	2016	25	New Jersey	2016	25	Pennsylvania	2016	28
Minnesota	2017	27	New Jersey	2017	26	Pennsylvania	2017	28
Minnesota	2018	32	New Jersey	2018	30	Pennsylvania	2018	29
Mississippi	2012	6	New Mexico	2012	25	Rhode Island	2012	22
Mississippi	2013	6	New Mexico	2013	25	Rhode Island	2013	22
Mississippi	2014	6	New Mexico	2014	26	Rhode Island	2014	25
Mississippi	2015	15	New Mexico	2015	26	Rhode Island	2015	26
Mississippi	2016	15	New Mexico	2016	26	Rhode Island	2016	30
Mississippi	2017	15	New Mexico	2017	26	Rhode Island	2017	34
Mississippi	2018	15	New Mexico	2018	26	Rhode Island	2018	34
Missouri	2012	13	New York	2012	27	South Carolina	2012	11
Missouri	2013	12	New York	2013	30	South Carolina	2013	12
Missouri	2014	12	New York	2014	32	South Carolina	2014	19
Missouri	2015	12	New York	2015	36	South Carolina	2015	20
Missouri	2016	12	New York	2016	39	South Carolina	2016	22
Missouri	2017	12	New York	2017	42	South Carolina	2017	22
Missouri	2018	12	New York	2018	47	South Carolina	2018	22
Montana	2012	18	North Dakota	2012	13	South Dakota	2012	11
Montana	2013	18	North Dakota	2013	13	South Dakota	2013	11
Montana	2014	18	North Dakota	2014	13	South Dakota	2014	15
Montana	2015	18	North Dakota	2015	15	South Dakota	2015	16
Montana	2016	18	North Dakota	2016	15	South Dakota	2016	14
Montana	2017	19	North Dakota	2017	14	South Dakota	2017	15
Montana	2018	19	North Dakota	2018	14	South Dakota	2018	15
Nebraska	2012	9	Ohio	2012	21	Tennessee	2012	7
Nebraska	2013	10	Ohio	2013	21	Tennessee	2013	7
Nebraska	2014	10	Ohio	2014	20	Tennessee	2014	7
Nebraska	2015	8	Ohio	2015	20	Tennessee	2015	7
Nebraska	2016	10	Ohio	2016	20	Tennessee	2016	7
Nebraska	2017	10	Ohio	2017	20	Tennessee	2017	6
Nebraska	2018	10	Ohio	2018	20	Tennessee	2018	5

State	Year	DG Score	State	Year	DG Score	State	Year	DG Score
Texas	2012	10	Virginia	2012	21	Wisconsin	2012	20
Texas	2013	12	Virginia	2013	23	Wisconsin	2013	19
Texas	2014	12	Virginia	2014	24	Wisconsin	2014	19
Texas	2015	14	Virginia	2015	24	Wisconsin	2015	19
Texas	2016	14	Virginia	2016	26	Wisconsin	2016	19
Texas	2017	13	Virginia	2017	32	Wisconsin	2017	18
Texas	2018	13	Virginia	2018	34	Wisconsin	2018	18
Utah	2012	25	Washington	2012	23	Wyoming	2012	10
Utah	2013	26	Washington	2013	24	Wyoming	2013	10
Utah	2014	27	Washington	2014	26	Wyoming	2014	10
Utah	2015	28	Washington	2015	26	Wyoming	2015	10
Utah	2016	28	Washington	2016	26	Wyoming	2016	10
Utah	2017	29	Washington	2017	27	Wyoming	2017	10
Utah	2018	26	Washington	2018	28	Wyoming	2018	10
Vermont	2012	23	West Virginia	2012	12			
Vermont	2013	24	West Virginia	2013	12			
Vermont	2014	26	West Virginia	2014	12			
Vermont	2015	30	West Virginia	2015	11			
Vermont	2016	30	West Virginia	2016	11			
Vermont	2017	32	West Virginia	2017	11			
Vermont	2018	33	West Virginia	2018	11			

Inventory of State Level Policy Changes, 2012-2018

State	Year	Legislation	Policy Code	Score Change
AL	2013	HB676	DG Reg	0
AL	2014	SB402	DG Reg	-1
AL	2015	HB629	DG Reg	0
AL	2015	SB459	DG Reg	0
AR	2013	HB2019	NEM-comprate	1
AR	2013	SB640	PACE	1
AR	2015	HB1004	NEM-cap	1
AR	2015	HB1633	DG Reg	1
AZ	2012	SB1229	DG Incentive	1
AZ	2014	SB1484	DG Incentive	1
AZ	2015	SB1465	DG Reg	1
AZ	2016	SB1417	DG Reg	1
CA	2012	AB1073	DG Reg	0
CA	2012	AB2165	DG Incentive	1
CA	2012	AB2514	DG Reg	1
CA	2012	SB594	DG Reg	1
CA	2012	SB1122	DG Reg	1
CA	2012	SB1128	DG Finance	1
CA	2012	SB1222	DG Incentive	1
CA	2012	SB1332	DG Incentive	1
CA	2013	AB792	DG Incentive	1
CA	2013	AB796	DG Reg	0
CA	2013	SB43	DG Reg	1
CA	2014	AB2188	DG Reg	1
CA	2014	SB871	DG Finance	1

State	Year	Legislation	Policy Code	Score Change
CA	2015	AB33	DG Reg	1
CA	2015	AB693	DG Finance	1
CA	2015	SB793	DG Reg	1
CA	2016	AB1637	NEM-cap	1
CA	2016	AB1773	DG Incentive	1
CA	2016	AB1923	NEM-cap	1
CA	2016	AB2313	DG Reg	1
CA	2016	AB2861	DG Reg	1
CA	2016	AB2868	DG Reg	1
CA	2016	SB840	DG Reg	1
CA	2016	SB259	DG Reg	1
CA	2017	AB36	NEM-tech	0
CA	2017	AB1414	DG Finance	1
CA	2017	AB398	DG Incentive	1
CA	2017	AB546	DG Reg	1
CA	2017	AB634	DG Reg	1
CA	2017	AB797	DG Incentive	1
CA	2017	SB338	DG Reg	1
CA	2017	SB700	DG Incentive	1
CA	2017	SB801	DG Reg	1
CA	2017	SB92	DG Incentive	1
CA	2018	SB1339	Interconnection	1
CA	2018	SB598	NEM-eligibility	1
CO	2013	SB273	DG Reg	1
CO	2014	HB1101	DG Incentive	1
CO	2014	HB1159	DG Incentive	0
CO	2015	HB1284	DG Reg	1
CO	2015	SB046	DG Incentive	1
CO	2015	HB1377	Community RE	1
CO	2015	HB1219	DG Finance	1
CO	2015	SB254	DG Reg	1
CO	2017	SB179	DG Incentive	1
CO	2018	SB9	DG Reg	1
CT	2012	SB25	DG Finance	1
CT	2012	SB501	DG Finance	1
CT	2013	HB647	DG Finance	1
CT	2013	SB1142	DG Reg	1
CT	2013	SB0203	DG Incentive	1
CT	2013	SB0946	DG Reg	1
CT	2013	HB6360	VNM	1
CT	2013	HB6706	VNM	0
CT	2014	HB5115	NEM-reg	0
CT	2014	SB357	DG Reg	0
CT	2015	HB6020	DG Finance	1
CT	2015	HB6838	DG Finance	1
CT	2015	HB6991	DG Finance	1
CT	2015	SB1078	DG Reg	1
CT	2015	SB928	VNM	1
CT	2016	HB5242	VNM	1
CT	2016	HB5427	VNM	1
CT	2016	HB5496	VNM	1
CT	2016	SB272	DG Finance	1

State	Year	Legislation	Policy Code	Score Change
CT	2016	SB366	DG Finance	1
CT	2016	SB394	VNM	1
CT	2017	HB7036	DG Finance	1
CT	2017	SB943	VNM	1
CT	2017	HB07208	DG Finance	1
CT	2018	SB9	NEM-successor	1
CT	2018	HB5574	DG Finance	0
DE	2015	HB93	DG Incentive	1
DE	2018	SB113	DG Finance	1
FL	2012	HB7117	DG Incentive	1
FL	2012	HB503	DG Incentive	1
FL	2013	HB277	DG Reg	0
FL	2014	HB7147	DG Reg	0
FL	2016	HB195	DG Reg	0
FL	2016	HB535	DG Reg	0
FL	2017	SB90	DG Incentive	1
GA	2012	HB386	DG Incentive	0
GA	2013	SB242	DG Reg	1
GA	2015	HB57	DG Finance	1
GA	2017	HB238	DG Reg	1
IA	2012	SB2342	DG Incentive	1
IA	2014	SB2340	DG Incentive	1
IA	2014	SF2343	DG Incentive	1
IA	2015	HF548	DG Reg	1
IA	2015	HF645	DG Incentive	0
IA	2018	SF2311	DG Reg	-1
ID	2016	HB534	DG Incentive	-1
IL	2012	SB3811	NEM-comprate	1
IL	2013	HB1070	DG Incentive	1
IL	2013	HB1201	DG Reg	-1
IL	2015	SB920	DG Reg	0
IL	2016	SB2612	DG Finance	0
IL	2016	SB2814	NEM-cap	1
IN	2012	HB1072	DG Incentive	1
IN	2013	HB1374	DG Finance	0
IN	2014	HB1423	DG Incentive	1
IN	2015	SB441	DG Incentive	-1
IN	2017	SB309	NEM-cap	1
KS	2013	HB2101	NEM-syscap	-1
KS	2015	SB91	DG Reg	-1
FL	2012	HB503	DG Incentive	1
FL	2013	HB277	DG Reg	0
FL	2014	HB7147	DG Reg	0
FL	2016	HB195	DG Reg	0
FL	2016	HB535	DG Reg	0
FL	2017	SB90	DG Incentive	1
GA	2012	HB386	DG Incentive	0
GA	2013	SB242	DG Reg	1
GA	2015	HB57	DG Finance	1
GA	2017	HB238	DG Reg	1
IA	2012	SB2342	DG Incentive	1
IA	2014	SB2340	DG Incentive	1

State	Year	Legislation	Policy Code	Score Change
IA	2014	SF2343	DG Incentive	1
IA	2015	HF548	DG Reg	1
IA	2015	HF645	DG Incentive	0
IA	2018	SF2311	DG Reg	-1
ID	2016	HB534	DG Incentive	-1
IL	2012	SB3811	NEM-comprate	1
IL	2013	HB1070	DG Incentive	1
IL	2013	HB1201	DG Reg	-1
IL	2015	SB920	DG Reg	0
IL	2016	SB2612	DG Finance	0
IL	2016	SB2814	NEM-cap	1
IN	2012	HB1072	DG Incentive	1
IN	2013	HB1374	DG Finance	0
IN	2014	HB1423	DG Incentive	1
IN	2015	SB441	DG Incentive	-1
IN	2017	SB309	NEM-cap	1
KS	2013	HB2101	NEM-syscap	-1
KS	2015	SB91	DG Reg	-1
KY	2013	SB46	DG Incentive	1
LA	2013	HB705	DG Incentive	0
LA	2015	HB779	DG Incentive	-1
LA	2016	HB766	DG Finance	-1
LA	2017	HB187	DG Incentive	-1
MA	2012	SB2395	DG Reg	1
MA	2012	S1915	DG Reg	1
MA	2014	S2138	DG Incentive	1
MA	2015	S1979	DG Incentive	1
MA	2016	H4412	DG Reg	0
MA	2016	H4568	DG Finance	1
MA	2016	H3881	DG Finance	0
MD	2012	SB1073	Transmission	1
MD	2012	HB1117	DG Reg	1
MD	2013	HB226	DG carve-out	1
MD	2013	HB621	DG Finance	1
MD	2013	SB370	DG Reg	0
MD	2013	SB887	DG Reg	0
MD	2014	HB1168	DG Reg	0
MD	2014	HB202	DG Finance	1
MD	2014	SB259	DG Reg	1
MD	2014	SB186	DG Finance	0
MD	2014	SB2	DG Reg	1
MD	2015	HB1087	DG Reg	1
MD	2015	SB353	Interconnection	1
MD	2015	HB105	DG Finance	1
MD	2016	HB1106	DG carve-out	1
MD	2016	HB440, SB811	Interconnection	1
MD	2016	SB936	DG Incentive	1
MD	2017	SB921	DG carve-out	1
MD	2017	SB758	DG Incentive	1
ME	2013	LD1652	DG carve-out	1
ME	2014	LS1750	DG Reg	0
ME	2015	LD1263	NEM	1

State	Year	Legislation	Policy Code	Score Change
ME	2015	LD1310	VNM	1
ME	2015	LD340	DG Reg	1
ME	2016	LD1676	PPA	1
ME	2016	LD1649	DG carve-out	0
ME	2018	LD1444	NEM-comprate	0
MI	2014	HB5397	DG Finance	1
MI	2016	SB437	NEM-comprate	0
MI	2016	SB438	NEM	1
MI	2017	SB375	DG Finance	1
MN	2013	HB729	NEM-syscap	1
MN	2013	HB854	DG Incentive	0
MN	2014	HB2834	DG Incentive	1
MN	2015	HF3	NEM-comprate	1
MN	2015	SF4	Fuel Incentive	1
MN	2017	SF1937	DG Incentive	1
MN	2017	SF1456	DG Incentive	1
MN	2018	HF3232	DG Incentive	1
MN	2018	SF3245	DG Incentive	1
MO	2013	HB142	DG Incentive	1
MS	2016	HB1139	NEM-comprate	0
MT	2017	SB7	NEM	0
MT	2017	SB32	Community RE	0
MT	2017	SB154	NEM	0
MT	2017	HB219	DG Reg	-1
MT	2017	SB11	DG Reg	1
NB	2012	LB742	DG Reg	1
NB	2013	LB402	DG Incentive	1
NB	2013	LB90	NEM-comprate	1
NB	2015	LB412	DG Incentive	1
NB	2015	LB424	DG Incentive	-1
NB	2016	LB1012	DG Finance	1
NB	2016	LB736	DG Reg	1
NB	2016	LB824	DG Reg	1
NB	2017	LB625	DG Finance	1
NC	2013	HB433	DG Reg	1
NC	2015	SB732	DG Incentive	0
NC	2017	HB589	DG Reg	1
ND	2013	HB1382	DG Incentive	1
ND	2015	SB2037	DG Incentive	0
ND	2017	SB2313	DG Reg	-1
NH	2012	HB1296	NEM-syscap	1
NH	2013	SB98	NEM-syscap	1
NH	2014	HB1600	DG Reg	0
NH	2016	HB1116	NEM-cap	1
NH	2016	SB378	VNM	1
NH	2018	HB1202	DG Finance	1
NH	2018	SB321	VNM	1
NH	2018	SB365	DG Reg	1
NH	2018	SB367	VNM	0
NH	2018	SB446	NEM-syscap	1
NJ	2012	SB1925	DG Reg	1
NJ	2012	AB2374	PACE	1

State	Year	Legislation	Policy Code	Score Change
NJ	2015	SB2420	NEM-statecap	1
NJ	2015	SB1138	DG Reg	0
NJ	2016	SB2204	NEM-tech	1
NJ	2016	S1969	DG Incentive	1
NJ	2016	SB988	DG Reg	0
NJ	2017	SB3181	DG Reg	0
NJ	2018	AB3723	DG carve-out	1
NJ	2018	SB1217	DG Reg	0
NM	2014	SB81	DG Incentive	1
NM	2015	HB296	DG Incentive	0
NM	2017	HB199	DG Reg	0
NM	2018	SB79	DG Incentive	0
NV	2013	AB428	NEM-statecap	1
NV	2015	SB374	NEM-statecap	-1
NV	2017	SB392	Community RE	0
NV	2017	AB405	NEM-statecap	1
NV	2017	AB405	NEM-comprate	2
NV	2017	AB5	DG Finance	1
NV	2019	SB300	NEM-comprate	1
NY	2012	S3203-B	DG Incentive	1
NY	2012	A34-B	DG Incentive	1
NY	2012	S6670	NEM-tech	1
NY	2012	A10620	DG Incentive	1
NY	2013	S4514	NEM-reg	0
NY	2013	A6366	NEM-tech	1
NY	2013	S1111	NEM-reg	0
NY	2013	S03806-C	NEM-syscap	1
NY	2013	S04770	DG Incentive	1
NY	2013	S05149	NEM-study	0
NY	2014	A08798	NEM-reg	1
NY	2014	S6485	NEM-syscap	1
NY	2014	S7026	DG Finance	0
NY	2014	S7293	DG Reg	1
NY	2014	S7464	DG Incentive	1
NY	2014	A6367	NEM	0
NY	2015	A4753	DG Incentive	0
NY	2015	A9925	DG Incentive	0
NY	2015	S7110	DG Incentive	1
NY	2017	A6571	DG Reg	1
NY	2017	A260	DG Incentive	1
NY	2017	S0688	DG Finance	1
NY	2018	A8921	DG Reg	0
NY	2018	A10150	DG Incentive	1
NY	2018	A11099	DG Incentive	1
NY	2018	A10410	DG Incentive	1
OH	2012	SB289	DG Reg	1
OH	2014	HB483	DG Reg	-1
OK	2013	SB343	DG Incentive	1
OK	2014	SB1456	DG Rate	-1
OK	2015	SB502	DG Incentive	-1
OK	2015	SB808	DG Reg	-1
OK	2017	HB2298	DG Incentive	-1

State	Year	Legislation	Policy Code	Score Change
OK	2018	HB3561	DG Reg	-1
OK	2018	SB1576	DG Reg	-1
OR	2013	HB2893	DG Incentive	1
OR	2013	SB561	DG Reg	1
OR	2014	HB4042	NEM-tech	1
OR	2014	HB4126	DG Reg	1
OR	2015	HB2193	NEM-cap	1
OR	2015	HB2941	DG Reg	1
OR	2015	HB3492	DG Incentive	0
OR	2015	SB752	DG Reg	0
OR	2016	HB4037	DG Incentive	1
OR	2016	SB1547	Community RE	1
OR	2017	HB2111	DG Reg	1
OR	2017	HB2132	DG Finance	1
OR	2017	HB2760	DG Incentive	1
OR	2017	HB3456	DG Reg	1
OR	2017	SB328	DG Reg	1
OR	2017	SB339	DG Reg	0
PA	2018	SB232	DG Finance	1
RI	2012	SB2792	DG Reg	1
RI	2013	SB641	DG Reg	0
RI	2013	HB6019	DG Finance	1
RI	2014	HB7727	DG Incentive	1
RI	2014	HB8010	NEM-eligibility	1
RI	2015	39-26.5-4.1	PACE	1
RI	2016	HB8180	Interconnection	1
RI	2016	HB8354	VNM	1
RI	2017	HB5199	DG Finance	0
RI	2017	HB5274	DG Incentive	1
RI	2017	HB5318	NEM-study	0
RI	2017	HB5483	Interconnection	1
RI	2017	HB5536	CCA	0
RI	2017	HB5575	Interconnection	1
RI	2017	HB5618	NEM-eligibility	1
SC	2013	HB3644	DG Incentive	1
SC	2014	SB1189	NEM-comprate	1
SC	2015	HB3874	DG Incentive	1
SD	2014	SB55	DG Incentive	1
SD	2015	HB1083	DG Reg	1
SD	2015	SB180	DG Incentive	1
SD	2016	HB1177	DG Incentive	-1
SD	2017	HB1012	DG Reg	0
TN	2013	HB62, SB1000	DG Incentive	0
TN	2015	HB1320	DG Incentive	1
TN	2017	HB1021	DG Reg	-1
TN	2018	HB1731	DG Reg	-1
TX	2013	HB2049	DG Reg	1
TX	2013	HB2500	DG Reg	0
TX	2013	HB2712	DG Incentive	1
TX	2013	SB385	PACE	1
TX	2015	HB706	DG Incentive	1
TX	2015	SB1626	DG Reg	1

State	Year	Legislation	Policy Code	Score Change
TX	2017	SB277	DG Reg	-1
UT	2013	SB221	DG Finance	1
UT	2013	HB284	DG Reg	0
UT	2014	SB224	DG Incentive	1
UT	2015	SB110	DG Reg	0
UT	2015	SB14	DG Reg	0
UT	2016	HB242	DG Incentive	0
UT	2016	HB244	DG Reg	0
UT	2017	SB154	DG Reg	0
UT	2017	SB273	DG Finance	1
UT	2018	HB261	DG Reg	1
UT	2018	SB141	DG Incentive	-1
UT	2018	SB157	DG Reg	1
UT	2018	SB166	DG Finance	1
VA	2012	SB627	DG Reg	0
VA	2012	HB129	DG Reg	0
VA	2012	HB448	NEM-charge	0
VA	2012	HB672	DG Reg	0
VA	2012	HB787	DG Incentive	0
VA	2013	HB1695	NEM-statecap	1
VA	2013	HB1917	DG Reg	0
VA	2013	HB2305	DG Reg	0
VA	2013	HB2334	DG Reg	1
VA	2014	HB1239	DG Incentive	1
VA	2015	HB1297	DG Reg	0
VA	2015	HB1950	NEM-syscap	1
VA	2015	HB2237	DG Reg	1
VA	2016	HB1220	DG Reg	1
VA	2016	HB1305	DG Incentive	1
VA	2017	HB2303	NEM	1
VA	2017	HB2390	DG Reg	1
VA	2017	SB1258	DG Reg	1
VA	2017	SB1393	DG Reg	1
VA	2017	SB1395	DG Reg	1
VA	2018	HB1451	NEM	1
VA	2018	HB508	DG Reg	1
VA	2018	SB902	DG Incentive	0
VA	2018	SB966	DG Reg	1
VT	2012	HB475	NEM-syscap	1
VT	2012	HB679	DG Incentive	-1
VT	2012	SB214	FIT-cap	1
VT	2013	HB395	DG Finance	1
VT	2014	HB702	NEM-cap	2
VT	2015	HB40	DG carve-out	1
VT	2017	SB52	DG Reg	1
VT	2017	HB411	NEM-credits	0
VT	2018	HB676	DG Incentive	1
VT	2018	SB276	Charges	1
WA	2012	HB2664	DG Reg	1
WA	2013	HB1614	DG Finance	0
WA	2013	SB5709	DG Reg	1
WA	2014	HB2708	DG Reg	1

State	Year	Legislation	Policy Code	Score Change
WA	2015	HB1095	DG Reg	1
WA	2017	SB5939	NEM-comprate	0
WA	2018	HB2580	DG Incentive	1
WI	2012	SB564	DG Incentive	1
WI	2012	SB425	DG Reg	1
WV	2012	HB2740	DG Reg	1
WV	2015	HB2001	NEM-repeal	-1
WV	2015	HB2004	NEM-create	1
WY	2013	HB40	DG Reg	-1
WY	2018	SB10	NEM-comprate	0

Notes on Data Collection – DG Policy Index

The method to collect data for the DG policy index involved multiple steps. This note will outline the process for compiling policy change data that was used for the quantitative analysis in Chapter Three.

1) *Establishing Baseline Scores*

First, I had to ascertain the baseline DG score for each state by taking the scores of the state-level policy environment prior to policy changes that were enacted within the 2012 to 2018 time period. To accomplish this, I relied on a variety of online resources that aggregate and summarize state energy policies. The Database of State Incentives for Renewable Energy, or DSIRE, contains information related to net metering programs, interconnection standards, DG carve-outs under Renewable Portfolio Standards (RPS), and other incentives and programs to promote deployment of DG technologies.[108] Program components that factored into the index were drawn from the DSIRE program pages, which contain the statutory and regulatory citations for each program's adoption and amendments. For example, the net metering program pages detail the compensation rate, the system size capacity limit, and the ownership of net metering

[108] Database of State Incentives for Renewable Energy (DSIRE), North Carolina Clean Energy Technology Center, https://www.dsireusa.org/

credits. The interconnection pages detail the system size capacity limit, whether rules facilitate a fast-track screening process, and eligible technologies.

After collecting the baseline data from DSIRE, I used additional resources to supplement and complete the information. The National Renewable Energy Laboratory, or NREL, details the policy components of DG programs in a technical report, "Midmarket Solar Policies in the US" (Tian et al. 2016). Similar to DSIRE, the Midmarket Policies report lists whether state DG policies allow for meter aggregation, virtual net metering, and the compensation structure for programs targeting systems in the mid-range of system capacity between 500 kW and 2 MW. The American Council for an Energy Efficient Economy contains information on net metering and interconnection programs for each state and was used as a resource to easily locate broad summaries of state policies and incentive programs.[109]

2) *Capturing Policy Changes*

Once baseline scores were established using the resources provided by DSIRE, NREL, and ACEEE, I then took the inventory of policy changes for each state between 2012 and 2018. DSIRE contains statutory and administrative code citations for the most significant policy developments, but DSIRE does not provide an exhaustive list of all the legislative and regulatory changes. To complete the list of policy changes from the initial baseline, I relied on the several resources.

First, the Center for the New Energy Economy, or CNEE, is a non-profit research institution that tracks all state-level energy legislation with the Advanced Energy Legislation

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[109] American Council for an Energy-Efficientt Economy (ACEEE), "Interconnection Standards," https://database.aceee.org/state/interconnection-standards; American Council for an Energy-Efficient Economy (ACEEE)," Deployment Incentives," https://database.aceee.org/state/deployment-incentives

Tracker tool, or AEL Tracker.[110] The tracker categorizes legislation based on policy type and associates bills with keywords, allowing the tracker to be used as a searchable database for bills related to net metering, interconnection, and other DG programs. CNEE also maintains a gap analysis tool called the State Policy Opportunity Tracker, or SPOT for Clean Energy.[111] SPOT highlights whether states have adopted key policy components of clean energy programs and provides links to legislation in tracker, if policies have corresponding legislation, and provides web links to the policy citations if they are not captured by the tracker. The tracker tool eased the process for taking an inventory of relevant DG policy changes throughout the time period.

Second, for policies related to green tariffs for commercial customers, I draw data from the Renewable Energy Buyer's Alliance and World Resources Institute's report on utility green tariffs.[112] The report details information on incentive structures that compensate mid- and large-sized systems that are a part of the data compiled for Chapter Three. For other policies related to corporate procurement, I included policies from the Advanced Energy Economy's report on utility programs to promote corporate access to renewables. [113]

Finally, in order to ensure that policy changes were not omitted from the dataset using the above resources, I searched the state legislative websites for all DG-related legislation from 2012-2018. I utilized a search strategy with keywords such as "net metering," "distributed generation," "interconnection," "community solar," and others in searching bill texts, subjects, and titles.

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[110] Center for the New Energy Economy (CNEE), "Advanced Energy Legislation Tracker," Colorado State University, https://www.aeltracker.org/
[111] Center for the New Energy Economy (CNEE), "SPOT for Clean Energy," Colorado State University, https://spotforcleanenergy.org/
[112] Bonugli, Celina, 2019. US Electricity Markets: Utility Green Tariff Update. Renewable Energy Buyer's Alliance and World Resources Institute, November 2019, https://rebuyers.org/us-electricity-markets-utility-green-tariff-update/
[113] Advanced Energy Economy (AEE), 2017. Expanding Access to Corporate Renewable Energy. September 7, 2017, https://aee.net

Appendix B – PUC Decisions Data

Inventory of Public Utility Commission Decisions

State	Year	Docket/proceeding no.	Policy Type	Ordered Logit Value (0-3)
Alabama	2015	32382	PPA	2
Arizona	2013	E-01345A-13-0248	NEM	0
Arizona	2016	E-01345A-15-0241	Storage	3
Arizona	2016	E-01933A-15-0239	Charges	0
Arizona	2016	E-04204A-15-0142	Charges	1
Arizona	2016	E-00000J-14-0023	NEM	0
Arizona	2016	E-00000J-14-0023	NEM	0
Arizona	2017	E-01345A-16-0036	NEM	2
Arizona	2017	E-01575A-15-0312	NEM	1
Arizona	2018	E-04204A-15-0142	NEM	1
Arizona	2018	E-01933A-15-0322	NEM	1
Arkansas	2012	12-001-R	NEM	2
Arkansas	2013	12-060-R	NEM	3
Arkansas	2017	16-027-R	NEM	3
California	2013	R1211005	Incentive	3
California	2014	R1211005	Interconnection	3
California	2015	R1211005	Incentive	1
California	2015	A1201008	Community RE	3
California	2015	R1410003	DER	3
California	2016	R1407002	NEM	2
California	2016	A1201008	Community RE	3
California	2016	R1109011	Interconnection	3
California	2016	R1410003	DER	3
California	2017	R1503011	Storage	2
California	2017	R1410003	DER	3
California	2017	R1407002	NEM	3
California	2017	R1407002	NEM	3
California	2018	R1407002	NEM	3
California	2018	R1407002	NEM	1
California	2018	R1807003	Interconnection	2
Colorado	2015	14M-0235E	NEM	3
Colorado	2016	15A-0847E	Project	2
Colorado	2016	15R-0699E	Community RE	3
Colorado	2016	16AL-0048E	NEM	3
Colorado	2016	16A-0055E	Community RE	2
Colorado	2016	16A-0139E	Community RE	2
Colorado	2017	17M-0131E	Interconnection	2
Colorado	2017	16A-0396E	DER	3
Colorado	2018	17D-0082E	Community RE	1
Colorado	2018	18R-0623E	Storage	3
Connecticut	2015	13-08-14RE02	Community RE	3
Connecticut	2016	15-09-03	NEM	2
Connecticut	2017	17-06-02	DER	2
Connecticut	2017	17-06-03	DER	2
Florida	2016	20150248	Community RE	2
Florida	2016	20160021	IRP	2
Florida	2017	20170183	IRP	2

Florida	2018	20170273	Third-party	3
Florida	2018	20180124	Third-party	3
Georgia	2012	36325	PPA	3
Georgia	2013	36325	PPA	2
Georgia	2015	36325	PPA	2
Georgia	2016	40161	DER	3
Idaho	2013	IPC-E-12-27	NEM	3
Idaho	2013	IPC-E-12-27	NEM	3
Idaho	2015	IPC-E-15-01	PPA	0
Idaho	2016	PAC-E-16-07	NEM	3
Idaho	2016	IPC-E-16-14	Community RE	3
Idaho	2017	PAC-E-17-11	PPA	1
Idaho	2018	IPC-E-17-13	NEM	0
Illinois	2016	15-0273	NEM	3
Illinois	2016	14-0135	Interconnection	3
Illinois	2018	17-0331	DER	2
Illinois	2018	17-0838	Incentive	2
Indiana	2018	45002-NONE	DER	2
Iowa	2016	NOI-2014-0001	NEM	3
Iowa	2016	RMU-2016-0003	Interconnection	3
Iowa	2018	RPU-2017-0001	NEM	3
Iowa	2018	RMU-2016-0006	Interconnection	2
Kansas	2017	16-GIME-403-GIE	DER	0
Kansas	2018	18-WSEE-190-TAR	PPA	2
Kentucky	2016	2016-00274	Community RE	2
Kentucky	2018	2017-00179	Tariff	2
Louisiana	2013	R-31417	NEM	0
Louisiana	2016	R-33929	NEM	1
Maine	2014	2013-00531	Interconnection	3
Maine	2017	2016-00222	NEM	0
Maryland	2017	RM56	Community RE	2
Massachusetts	2012	11-10-A	NEM	1
Massachusetts	2012	11-11-A	NEM	1
Massachusetts	2013	11-75-E	Interconnection	3
Massachusetts	2016	15-155	NEM	3
Massachusetts	2018	17-05	Charges	2
Massachusetts	2018	17-22	NEM	2
Massachusetts	2018	17-140	Tariff	2
Michigan	2016	17875	DER	2
Michigan	2017	U-18090	PURPA	2
Michigan	2017	U-18393	Tariff	2
Michigan	2017	U-18090	PURPA	3
Michigan	2018	U-18383	NEM	0
Michigan	2018	U-18352	Tariff	3
Michigan	2018	U-18351	Tariff	2
Minnesota	2014	14-65	DER	3
Minnesota	2014	13-867	Community RE	3
Minnesota	2015	13-867	Community RE	2
Minnesota	2016	15-825	Community RE	2
Minnesota	2016	13-867	DER	2
Minnesota	2016	16-512	Charges	2
Minnesota	2016	16-240	Charges	2
Minnesota	2016	16-241	NEM	3

Minnesota	2017	16-485	Incentive	3
Minnesota	2017	15-985	Tariff	2
Minnesota	2017	16-512	Charges	2
Minnesota	2018	13-867	DER	3
Minnesota	2018	16-521	Interconnection	3
Minnesota	2018	13-867	DER	3
Minnesota	2018	14-643	DER	3
Mississippi	2015	2011-AD-2	NEM	2
Mississippi	2016	2016-UN-32	NEM	2
Mississippi	2016	2016-UN-33	NEM	1
Missouri	2013	ET-2014-0071	Incentive	0
Missouri	2016	ET-2016-0185	Incentive	0
Missouri	2016	EA-2016-0207	Community RE	2
Missouri	2016	EA-2016-0208	DER	1
Missouri	2017	ER-2016-0179	Charges	2
Missouri	2018	ET-2018-0063	Tariff	2
Missouri	2018	EA-2016-0207	Community RE	2
Montana	2016	D2015.6.51	NEM	2
Nevada	2012	11-07021	Incentive	3
Nevada	2012	12-05039	Charges	1
Nevada	2013	12-11023	Tariff	2
Nevada	2014	13-06018	Charges	0
Nevada	2015	15-07021	NEM	1
Nevada	2016	15-06054	Charges	1
Nevada	2016	15-07041	NEM	0
Nevada	2016	16-07028	NEM	1
Nevada	2016	16-06006	NEM	3
Nevada	2016	16-07001	DER	2
Nevada	2017	17-07026	NEM	3
Nevada	2018	17-07026	NEM	3
Nevada	2018	17-08021	Storage	3
Nevada	2018	17-07020	DER	3
Nevada	2018	17-08022	DER	2
New Hampshire	2015	DE 15-302	Incentive	0
New Hampshire	2016	DE 15-303	PPA	3
New Hampshire	2017	DE 16-576	NEM	1
New Jersey	2013	QO16060487	NEM	3
New Jersey	2018	Q018070697	Community RE	2
New Mexico	2015	15-00127-UT	Charges	3
New Mexico	2017	17-00022-UT	Storage	3
New York	2012	12-E-0105	NEM	3
New York	2012	12-E-0343	NEM	3
New York	2013	12-02354	Community RE	3
New York	2013	12-E-0485	NEM	3
New York	2014	14-E-0151	NEM	3
New York	2015	15-E-0082	Community RE	3
New York	2015	14-00581	DER	3
New York	2015	15-01526	NEM	3
New York	2016	15-01954	Interconnection	3
New York	2016	15-E-0757	Community RE	3
New York	2016	14-01211	CCA	3
New York	2016	14-00581	DER	3
New York	2016	15-01056	NEM	3

New York	2017	15-E-0751	DER	3
New York	2017	15-E-0751	DER	3
New York	2017	15-00733	DER	2
New York	2018	15-E-0751	DER	3
New York	2018	15-02703	Interconnection	3
New York	2018	15-E-0082	Community RE	3
New York	2018	15-E-0751	DER	3
New York	2018	18-00516	Storage	3
North Carolina	2015	E-100 Sub 140	PPA	1
North Carolina	2015	E-100, SUB 101	Interconnection	3
North Carolina	2016	SP-100 Sub 31	Third-party	0
North Carolina	2017	E-100 Sub 148	PPA	1
North Carolina	2017	E-100 Sub 148	Community RE	1
North Carolina	2018	E-100 Sub 156	Third-party	2
North Carolina	2018	E-2 Sub 1159	DER	2
North Carolina	2018	E-2 Sub 1167	Incentive	2
Ohio	2013	12-2051-EL-ORD	Interconnection	1
Ohio	2017	12-2050-EL-ORD	NEM	0
Oklahoma	2016	PUD-201500340	Community RE	2
Oklahoma	2016	PUD-201500274	Charges	2
Oklahoma	2017	PUD-201500273	Charges	2
Oklahoma	2018	PUD-201700496	Tariff	2
Oregon	2016	UM 1725	PPA	3
Oregon	2016	UM 1734	PPA	3
Oregon	2017	UM 1793	Charges	1
Oregon	2017	UM 1716	DER	2
Oregon	2018	UM 1930	Community RE	3
Pennsylvania	2012	M-2011-2249441	Third-Party	3
Pennsylvania	2016	L-2014-2404361	NEM	3
Pennsylvania	2016	L-2014-2404361	NEM	2
Rhode Island	2016	4568	Charges	2
Rhode Island	2016	4631	NEM	3
Rhode Island	2017	4670	Community RE	3
Rhode Island	2017	4483	Interconnection	3
Rhode Island	2017	4743	NEM	2
Rhode Island	2018	4790	NEM	2
South Carolina	2015	2014-246-E	NEM	2
South Carolina	2015	2015-55-E	DER	2
South Carolina	2015	2015-54-E	DER	2
South Carolina	2015	2015-53-E	DER	2
South Carolina	2016	2015-362-E	Interconnection	3
South Carolina	2016	2015-54-E	DER	2
South Carolina	2017	2017-2-E	PPA	1
Tennessee	2016	1600001	NEM	2
Texas	2012	39797	Third Party	3
Texas	2016	44941	Charges	2
Texas	2016	45078	Interconnection	3
Texas	2017	46957	DER	2
Texas	2017	46831	Charges	1
Utah	2015	15-035-61	Community RE	2
Utah	2016	16-035-T09	PPA	2
Utah	2016	16-035-36	Project	2
Utah	2017	16-035-36	Project	2

Utah	2017	14-035-114	NEM	1
Vermont	2016	8652	NEM	3
Vermont	2016	6/30/2016	NEM	3
Vermont	2018	18-0086-INV	NEM	3
Virginia	2015	PUE-2015-00057	NEM	3
Virginia	2016	PUE-2015-00040	Third-party	1
Virginia	2016	PUE-2016-00050	DER	3
Virginia	2017	PUE-2016-00094	Tariff	3
Virginia	2018	PUR-2017-00109	DER	3
Virginia	2018	PUR-2017-00137	DER	3
Virginia	2018	PUR-2017-00060	Tariff	1
Virginia	2018	PUR-2018-00009	Community RE	2
Virginia	2018	PUR-2017-00163	Tariff	2
Washington	2017	U-161024	Storage	3
Wisconsin	2014	5-UR-107	NEM	0
Wisconsin	2015	4139-TE-102	Community RE	2
Wisconsin	2016	3270-TE-101	Community RE	2
Wisconsin	2017	3270-TE-102	Tariff	2
Wisconsin	2018	4220-TE-102	Tariff	2
Wisconsin	2018	6630-TE-102	Tariff	2
Wyoming	2016	20000-481-EA-15	PPA	2
Wyoming	2018	20000-518-ET-17	PPA	0

Notes on Data Collection – PUC Decisions

Data collection for Chapter Four's analysis on PUC decisions involved a similar process as Chapter Three. I first collected the most significant policy changes in DSIRE, but the regulatory dataset required a deeper dive into state commission regulatory dockets. State PUCs publish decisions on state websites along with the docket reference number. Each docket contains a record of the commissions' proceedings, and entries within the docket indicates the type of document, such as testimony, hearing, public notice, PUC orders, etc. All the dockets listed in this appendix are publicly available and searchable from the web pages of the state commissions and/or regulatory agencies. However, the state commissions websites are not uniformly easily accessible or navigable, though the locating dockets with the docket number tends to be straightforward. The primary difficulty in researching PUC regulations is that dockets are not organized to be easily searchable. Most websites organize dockets by industry category, but there are few tools implemented to search for PUC regulations based on policy type or antecedent legislation.

Instead of beginning the data collection process by searching for the issuance of orders and regulations through websites, I used an online clearinghouse portal developed by the Advanced Energy Economy, or AEE, called *Powersuite*.[114] Powersuite contains a database of PUC dockets within the selected timeframe as well as in preceding years for some states. To utilize the docket search tool, I employed a two-pronged approach: 1) keyword combinations, similar to the legislation searches used for the DG policy index (net metering, interconnection, etc.), and 2) the "AEE Watch List," which categorizes PUC dockets based on policy type and designates whether dockets involved significant rule changes and policy adoptions. The Powersuite tool proved instrumental for locating the necessary PUC regulations, particularly after having collected the policy change data for the DG policy index. Moreover, the tool provides link to the source of regulatory changes, saving time on locating the universe of dockets relevant to DG and renewable energy. After searching for the relevant policies for each state in Powersuite, I proceeded to search the state websites to ensure that no significant DG rule changes were omitted from the dataset, ultimately collecting 228 decisions.

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[114] Advanced Energy Economy (AEE), "Powersuite: All Dockets," https://powersuite.aee.net/dockets/search/all

Glossary

Advanced Metering Infrastructure (AMI) – Also called "smart meters," AMI allows utilities precisely measure and control the flow of electricity to end uses and enables a variety of efficiency and load management programs.

Aggregate Net Metering – Modifies net metering programs by allowing consumers to earn NEM credits at multiple meters located either within the same property or across adjacent parcels. Especially beneficial for agricultural customers, public entities, and multifamily housing.

Ancillary Services – Refers to variety of grid and energy management mechanisms enabled by AMI, such as frequency regulation and energy imbalance correction.

Avoided Cost Rate – The rate at which utilities must pay renewable facilities for exported electricity under the Public Utilities Regulatory Policy Act, and the default rate absent a state-mandated retail rate net metering program. The rate factors in the costs of infrastructure maintenance and service provision that is saved by the utility purchasing renewable energy instead of generating and transmitting electricity from its owned assets.

Base Load Generation – Electricity generation that can provide a steady supply of electricity to constantly meet a minimum level of demand. Contrast with peaking such as certain natural plants or variable/intermittent resources such as renewables. Base load generally refers to coal and nuclear power plants.

Combined Heat and Power (CHP) – Also called cogeneration, CHP refers to projects that use the heat by-product from on-site electric generation to direct thermal energy toward heating for buildings or heating districts.

Community Choice Aggregator (CCA) – a policy that allows municipalities to procure renewable electricity from energy providers outside the service area of the incumbent utility.

Community Solar – A utility incentive program in which members can opt-in or subscribe to a renewable project sited on the distribution system intended to provide electricity service to residences or businesses. Subscribers would "own" a portion of the renewable facility as if the project were sited on their property, allowing them to offset their electricity consumption and potentially earn net metering credits to use against future electricity bills. Community solar policies depend upon a complimentary enabling policy: virtual net metering (see below). Includes Community Solar Gardens (CSGs).

Cost-shifting – Created as a result of the retail rate scheme under DG programs and revenue requirement structure. Refers to the ability of DG customers to circumvent fixed charges through the self-generation incentive under a net metering program, leaving non-DG customers responsible for paying grid costs. Often used interchangeably with *cross-subsidization*.

Decoupling – A mechanism applied to utilities' revenue requirement that attempts to remove the disincentive for energy efficiency programs. Utilities are guaranteed a rate-of-return based on their performance toward the satisfaction of certain public policy objectives, such as energy conservation, rather than volumetric electricity sales.

Demand Response (DR) – Enabled by AMI, DR is a tool that allows grid operators to limit consumption on the consumer's side of the meter to mitigate stain on the grid during times of peak demand.

Demand-Side Management (DSM) – Includes various mechanisms to control the balance of grid supply and demand on the distribution network, including demand response and energy efficiency programs.

Distributed Energy Resources (DER) - Included not only on-site generation, but also any technology that is located "behind the meter" and on the distribution network that provides value to the grid in terms of electricity supply or demand management capabilities, such as energy efficiency programs, smart meters, and ancillary services.

Distributed Generation (DG) – Power production technology that is located on the distribution network at or near the point of consumption. Also referred to as on-site or behind-the-meter generation. Rooftop solar is the most ubiquitous DG technology, but DG also can include biomass, geothermal, small wind, small hydro, and other resources.

Electric Cooperative – Associations of ratepayers in that purchase electricity from regulated providers, located in predominantly rural areas. Distribution cooperatives purchase electricity from generation/transmission cooperatives on a wholesale basis, making them subject to federal regulation under the Federal Power Act. PUCs exercise less authority over cooperatives than integrated utilities.

Energy Efficiency Resource Standard (EERS) – A state regulatory program that requires utilities to meet annual or semi-annual electricity consumption reduction targets, usually measured as a percentage of the utility's peak sales in a given year.

Federal Energy Regulatory Commission (FERC) – The federal agency that oversees wholesale interstate electricity markets. Exercises authority over independent system operators, competitive providers that sell electricity out-of-state, and certain electric cooperatives.

Feed-in Tariff (FIT) – A program that provides direct incentive payments on a per-kilowatt hour basis for electricity provided to the grid from renewable sources. Participants in a FIT program are paid as if they were utility providers, since they are directly compensated to energy provided to the grid. The value of FIT payments may be calculated to reflect the "non-energy" attributes of renewable technologies, such as environmental benefits, resiliency or reliability, and deferred infrastructure costs, as in a Value of Solar or Distributed Energy Resource program (see below).

Franchise Agreements – Established between the utility and the municipal government, establishes utility rights-of-way and license to operate.

Hosting Capacity – A measure of the technical constraints of the distribution system; captures the ability of the distribution network to integrate power production sources such as DG.

Independent Power Provider (IPP) – Electricity producers separate from the incumbent utility, legally defined by the Public Utilities Regulatory Policy Act of 1978.

Independent System Operator (ISO) - Quasi-governmental independent entities that manage grid supply across multiple states. ISOs are regulated by FERC to foster competition and more efficiently allocate resources.

Integrated Distributed Planning (IDP) - an addendum to utilities' integrated resource plans and requires the inclusion of planning for and coordination of distributed energy resources. IDP is an essential component of grid modernization.

Integrated Resource Plan (IRP) – Developed by utilities and approved by the PUC, the IRP is a large technical document that details the utility's planned investments, forecasted demand, and system costs over long time horizons, usually between 10 and 30 years.

Interconnection Standards – Policy that defines the requirements and process for connecting DG systems to the utility system.

Investor-Owned Utilities (IOUs) – Private entities which are the primary regulated entity by PUCs and serve the bulk of electricity customers in the US.

Levelized Cost of Energy (LCOE) – Also called the levelized cost of electricity, LCOE is a measure to evaluate the relative cost across source of energy and is determined by calculating the revenue needed to recover costs for a system's given life cycle.

Lost Revenue Adjustment Mechanism (LRAM) – Provides utilities with a financial incentive to adopt energy efficiency programs by partially covering the lost revenue as a result of decreased consumption due to energy conservation measures.

Microgrid – distributed generation systems paired with battery storage, allowing power generation to continue amidst grid outages.

Nameplate Capacity – The size of the power production system, expressed in terms of rated power output in wattage.

Natural Gas Combined Cycle (NGCC) – Relatively large capacity natural gas plants that serve as a reliable source of electricity generation; contrast with rapid "peaker" plants that can be rapidly turned online or offline

Net Energy Metering (NEM) – A program that compensates DG customers with kilowatt-hour credits for electricity produced that exceeds their consumption, allowing a customer to offset their electricity bill. NEM programs have a variety of designs, but many organizations defined "net metering" as compensating excess generation credits at the retail rate of electricity.

Photovoltaics (PV) – The primary technology for solar electricity generation and refers to the process of converting light into energy.

Power Purchase Agreement (PPA) – A program that enables customers to purchase electricity from a renewable system owned by the private company through a long-term contract, typically in periods of 10 or 20 years.

Property Assessed Clean Energy (PACE) – A financing tool that allows electricity customers to enter into long-term agreements to pay back the cost of renewable energy or energy efficiency equipment through a special levy on their property tax bill. Before PACE can be implemented, the state legislature must authorize local governments to grant themselves bonding authority to finance the program and is administered by a third party.

Public Utility Commission (PUC) – The state regulatory agency that oversees all rate-regulated utilities and exercises unique authority over the retail electricity sector. Approves or disapproves of resource and rate decisions made by electric power companies.

Qualifying Facilities (QFs) - small renewable power production facilities that include hydroelectricity, wind, solar, biomass, waste energy, or geothermal electric generation. Also includes combined heat and power QFs are defined under the Public Utilities Regulatory Policies Act of 1978.

Rate Case – Regular PUC proceedings in which PUCs establish the revenue requirement, which determines customer electricity rates. Utilities may present evidence to the commission to justify a rate increase, or propose a rate decrease, given the utility's shifting operating costs. Those costs might then be incorporated into the rate-of-return, allowing utilities to recover investment costs through customer bills.

Regional Transmission Organization (RTO) – See Independent System Operator.

Renewable Portfolio Standards (RPS) – A state regulatory policy that mandates utilities to provide a minimum percentage of electricity generation from renewable sources.

Restructuring – Refers to the regulatory framework governing the state's electricity market. In contrast with traditionally regulated, vertically integrated states, restructured states allow nonutility entities to sell power to utilities, and in some cases, retail providers independent of rate-regulated utilities may sell electricity directly to customers. Restructured states have also been called "retail competition" states.

Small Generator Interconnection Procedures (SGIP) – FERC's model interconnection standards that outline a clear process and technical requirements to allow distributed generation facilities to integrate to the power grid.

Time-of-Use (TOU) – An innovative market tool that sets electricity rates as varying on a daily, hourly, or sub-hourly basis and can more precisely reflect the true cost of operating infrastructure to serve demand at peak times of day.

Variable Energy Resources (VERs) – refers to renewable resources such as solar and wind, which have variable energy production as a result of intermittent weather conditions.

Virtual Net Metering (VNM) – Extends net metering by allowing customers who are located outside/off-site from the electricity meter to earn net metering credits for net excess generation. A critical policy for enabling community solar programs.

Value of Distributed Energy Resources (VDER) Tariff – An innovative alternative to retail rate net metering. Compensates DER projects for several benefits provided to the grid, including the energy value, capacity value, environmental value, demand reduction value, and locational system relief value. Generally, includes Performance Incentive Mechanisms (PIMs) that compensate utilities for outcomes they are not otherwise incentivized to achieve under the conventional business model, such as social equity, environmental conservation, and resilience.

Value of Solar Tariff (VOST) – See Value of Distributed Energy Resources.