UTILITIES' DUTY TO SERVE IN AN ERA OF END-USE ELECTRIFICATION

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Synopsis: Load growth has returned to utilities' distribution systems. At the same time as data centers and manufacturing are driving up electricity demand at the transmission and generation level (a subject that would warrant its own article), end-use electrification—the electrification of sectors historically reliant on fossil fuels, such as transportation and building space and water heating—is responsible for a growing need for utilities to expand and upgrade distribution infrastructure. This trend is placing new pressures on utilities to adapt their forecasting, planning, and building practices to serve these new loads. This article considers how the duty to serve, a bedrock component of public utilities' legal obligations, should inform the specific expectations placed on utilities by their regulators for modifying or expanding their distribution facilities to serve these loads. This includes consideration of the specific characteristics of these loads, as well as utilities' tools to forecast, plan for, and accommodate them. Lastly, this article discusses the extent to which utilities' existing legal duty to serve will—or may already—obligate them to anticipate and prepare for future end-use electrification loads.

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I. INTRODUCTION

Electric utilities have a duty to serve their customers. This duty, derived from both the common law origins of public utility regulation and the state statutes outlining the responsibilities of utilities and the agencies that regulate them, generally obligates utilities to connect new customers in their service territory to the electric grid and to continue providing adequate service.[1] The duty is not limitless, but utilities must generally make all "reasonable" extensions of service customers request, even when an individual extension may not be profitable.[2]

And those grid connections are suddenly a hot commodity. After several decades of little to no growth in total electricity demand in the U.S., demand is growing once again.[3] A rapid expansion of artificial intelligence data center deployments, newfound growth in electrified domestic manufacturing, and electrification of home heating and transportation[4] are driving a scramble for utilities and regulators to determine utility system needs.[5] The heterogeneity of these load sources further complicates this task: large industrial and data center loads that elect to connect to the grid typically take service directly from the transmission system, and therefore primarily affect transmission and generation systems; whereas end-use electrification's impacts arise most acutely on distribution systems.[6] These systems are subject to different regulatory regimes and thus pose

1. *See generally* Munn v. Illinois, 94 U.S. 113 (1877) (relying heavily on English common law in finding that states have the authority to regulate private businesses providing public services); Kristin George Bagdanov, *Decarbonizing the Obligation to Serve*, BLDG. DECARBONIZATION COAL. 23-36 (Mar. 5, 2025), https://buildingdecarb.org/wp-content/uploads/FINAL_Decarbonizing-the-Obligation-to-Serve_Oct2024.pdf (providing the statutory duty to serve provision of all 50 states and Washington, D.C.).

2. *See* Jim Rossi, *The Common Law "Duty to Serve" and Protection of Consumers in an Age of Competitive Retail Public Utility Restructuring*, 51 VAND. L. REV. 1233, 1252-53 (1998); *See* New York *ex. rel*. New York & Queens Gas Co. v. McCall, 245 U.S. 345, 351 (1917) ("Corporations which devote their property to a public use may not pick and choose, serving only the portions of the territory covered by their franchises which it is presently profitable for them to serve and restricting the development of the remaining portions by leaving their inhabitants in discomfort without the service which they alone can render. To correct this disposition to serve where it is profitable and to neglect where it is not, is one of the important purposes for which these administrative commissions, with large powers, were called into existence. . . . ").

3. *See* Stéphanie Bouckaert & Timothy Goodson, *The Mysterious Case of Disappearing Electricity Demand*, INT'L ENERGY AGENCY (Feb. 14, 2019), https://www.iea.org/commentaries/the-mysterious-case-of-disappearing-electricity-demand.

4. As of this writing, the extent to which each of these sources contributes to electric demand growth remains unclear, particularly given wide variability in data center load forecasts. *See Tracking Electricity Consumption from U.S. Cryptocurrency Mining Operations*, U.S. ENERGY INFO. ADMIN. (Feb. 1, 2024), https://www.eia.gov/todayinenergy/detail.php?id=61364 [hereinafter *Tracking Electricity Consumption*].

5. John D. Wilson et al., *Strategic Industries Surging: Driving US Power Demand*, GRID STRATEGIES 3 (Dec. 2024), https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf ("The official nationwide forecast of electricity demand shot up from 2.8% to 8.2% growth over the next five years to 66 GW through 2029 -- but with an additional 61 GW of growth in preliminary updates, **nationwide electric demand is forecast to increase by 15.8% by 2029**.").

6. *See Characteristics and Risks of Emerging Large Loads*, N. AM. ELEC. RELIABILITY CORP. 9-11 (July 2025), https://www.nerc.com/comm/RSTCReviewItems/3_Doc_White%20Paper%20Characteristics%20and%20Risks%20of%20Emerging%20Large%20Loads.pdf (describing how different independent system operators (ISO)/regional transmission organizations (RTO) define large loads (e.g. by voltages above 115kV or peak loads above 75 megawatts) and how the ISO/RTO must evaluate transmission service applications by these loads).

different questions about the scope of a utility's duty to serve. These questions are important, but are too broad to cover in one article, so this piece focuses on the utility obligations to serve as they relate to the planning, construction and operation of distribution system infrastructure.

At the distribution level, where utilities work most directly under the eye of state regulators, the most significant driver of new load is end-use electrification, generally defined to include any growth in electricity consumption that replaces fossil fuel consumption.[7] This includes homes replacing furnaces running on fossil gas or home heating oil with heat pumps, electric vehicles and chargers taking the place of gasoline- and diesel-powered vehicles and fueling stations, and businesses replacing innumerable types of equipment with electrified versions. These load sources frequently come online much faster than comparably sized traditional loads. For example, an electric truck charging depot can have the same electric demand as a municipality but can be built in a fraction of the time.[8]

Early evidence suggests that utilities' historical distribution system planning and interconnection practices struggle to keep up with customers' end-use electrification. In California, the state at the forefront of transportation electrification in the U.S., fleets and charging station operators regularly report multi-year delays in connecting their chargers to the grid.[9] They are not alone, with housing, agriculture, telecommunications, and local government customers reporting similarly long timelines.[10] Other states with electrification or climate policies that encourage end-use electrification are feeling similar pressures. Regulators in several such states, including Minnesota, New York, Colorado, and Massachusetts, have acknowledged that more proactive efforts on the part of utilities to prepare their

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7. This is not to suggest that generation and transmission facility adequacy is not also a concern of state regulators, particularly in those "vertically-integrated" states where utilities provide bundled retail service. But that is outside the scope of this article.

8. *See Staff Proposal for the High DER Proceeding*, CAL. PUB. UTILS. COMM'N ENERGY DIV., at 51 (Mar. 13, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF [hereinafter *Staff Proposal*] ("the EV charging depots needed to facilitate transportation and freight electrification, which can demand the power equivalent to a small town, can be installed by developers in a matter of weeks.").

9. *See* Opening Comments of Powering America's Commercial Transportation on the Administrative Law Judge's Ruling Directing Parties to Respond to Questions on Energization Issues, Rulemaking No. 24-01-018, at 6 (Cal. Pub. Utils. Comm'n June 18, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K105/534105479.PDF [hereinafter Opening Comments] ("PACT members have shared anecdotal information regarding utility responses to 2-5 MW projects in Southern California, noting that these requests are frequently quoted an energization date into 2029. Most of those projects are then put on hold, postponed, or canceled because of this lengthy energization timeline.").

10. *See, e.g.*, Comments of City and County of San Francisco on Order Instituting Rulemaking to Establish Energization Timelines, Rulemaking No. 24-01-018, at 2 (Cal. Pub. Utils. Comm'n Feb. 20, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M525/K670/525670863.PDF ("San Francisco has historically experienced delays to the energization of essential projects that required service from the electrical distribution grid."); Comments of California Broadband & Video Association in Response to Order Instituting Rulemaking to Establish Energization Timelines, Rulemaking No. 24-01-018, at 2 (Cal. Pub. Utils. Comm'n Feb. 20, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M525/K362/525362121.PDF ("In CalBroadband members' experience, it can often take up to 18 months, and sometimes much longer, for the IOUs to energize a power supply after communications service providers submit an application"); Motion for Party Status of the Agricultural Energy Consumers Association, Rulemaking No. 24-01-018, at 2 (Cal. Pub. Utils. Comm'n Feb. 29, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M526/K148/526148061.PDF ("Some AECA members have been told they must wait six years to get the power necessary.").

systems for electrification-driven load growth are needed.[11] But energization delays will not be limited to those states. While state policy and regulation is a major driver of electrification in the near-term, as electrification technologies continue to become cost-competitive even in the absence of policy support, they will increasingly pose challenges to distribution utilities across the country.

The accelerating need for utilities to upsize their distribution grids, and the cost implications of doing so, raise several questions regarding how the duty to serve should be applied in this context. What can regulators reasonably expect of utilities when it comes to forecasting these future loads? How should utilities be adapting their planning processes in light of these updated forecasts? Does the duty to serve include a timeliness component, and if so, how should it be defined? What are utilities' obligations with respect to emerging practices that can accelerate the service connection process for customers?

This article seeks to propose answers to such questions. It posits that utilities' duty to serve inherently includes the obligation to account for incoming end-use electrification, and that utilities that fail to do so will increasingly find themselves at legal risk.

The remainder of this article is structured as follows. Part I summarizes the historical basis of the duty to serve, and the used-and-useful and prudence tests as applied to public utilities. Part II discusses the impacts to the distribution grid utilities, and their regulators, can expect from end-use electrification. Part III addresses how utilities' duty to serve can be interpreted to reasonably meet the needs of customers with end-use electrification load, including anticipating future loads and providing adequate service. Part IV concludes and discusses topics warranting further scholarship.

II. HISTORY OF THE DUTY TO SERVE, USED-AND-USEFUL TEST, AND PRUDENCE TEST

A. Duty to Serve

Like much of U.S. law, utilities' duty to serve has its roots in English common law from the 19th century and earlier.[12] The duty was driven by the realities

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11. *See* Order Establishing Proactive Planning Proceeding, No. 24-E-0364, at 4 (N.Y. Pub. Serv. Comm'n Aug. 15, 2024), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80465791-0000-C51E-B4A0-7B56E347E0F5} ("The Commission is instituting this proceeding to establish a statewide, collaborative framework for proactive planning to support the needs of New Yorkers as we focus on electrification of the transportation and building sectors to further our climate change goals."); Notice Soliciting Stakeholder Members, Docket No. CI-24-318, at 1 (Minn. Pub. Utils. Comm'n Sept. 26, 2024), https://efiling.web.commerce.state.mn.us/documents/%7BC0452F92-0000-CE12-AED7 A7BB3DD051CB%7D/download?contentSequence=0&rowIndex=6 (creating a stakeholder working group to "develop a framework for proactive upgrades and cost allocation for Commission consideration and possible adoption."); Notice of Proposed Rulemaking, Decision No. 20R-0516E, at 30 (Colo. Pub. Utils. Comm'n Nov. 25, 2020), https://www.sos.state.co.us/CCR/Upload/NoticeOfRulemaking/AddInfoAttach2020-00933.pdf; Order Approving Electric Sector Modernization Plans, Docket No. 24-10, 24-11, and 24-12, at 13-14 (Mass. Dep't of Pub. Utils. Aug. 29, 2024), https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//igggdddj?dFR-GoJKkAru50g4f2swgdmFJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMlNqhcS-kxPf0qUr1gASPKrYE1qejvebf677PtCVStUdHoHpEGELGLGjR+ZpYgt.

12. Rossi, *supra* note 2, at 1244.

of operating certain businesses. Mills and ferries, for example, provided necessary services for the communities they served but required large capital investments that made competitive service from other entities infeasible or ultimately harmful to the provision of any service at all.[13] Allowing these services to operate as monopolies, however, ran the risk that the operator could overcharge or exclude customers, ultimately harming the public interest. To avoid this outcome, judges created a duty to serve, under which the holder of such a monopoly (also known as a franchise) serves anyone wishing to use their services.[14]

In its absorption and adaptation into U.S. law around the turn of the 20th century, the duty to serve was useful for stemming the anticompetitive practices of new monopoly-holders such as railroads.[15] At the time, railroads would regularly offer particular customers such as Standard Oil lower rates than other shippers in exchange for all of their business.[16] State courts repeatedly found that through their role as common carriers and holders of a state-granted monopoly, the duty to serve obligated railroads not only to serve all prospective customers but also to treat those customers equally with respect to their costs of service.[17] The Supreme Court endorsed a broad conception of the duty, finding in *Munn v. Illinois* that states could regulate the rates of private businesses when "necessary for the public good" and where the private property in question is "affected with a public interest."[18] And the Court went even further in *Nebbia v. New York*, finding that "there is no closed class or category of businesses affected with a public interest . . . ."[19] Instead, "'affected with a public interest' can, in the nature of things, mean no more than that an industry, for adequate reason, is subject to control for the public good."[20]

U.S. courts incorporated the duty to serve into the obligations of industries we now identify as public utilities at this time as well, including water, telephone and gas utilities.[21] Even before the enactment of statutes outlining the duty and creating the regulatory agencies that would eventually enforce it, state courts widely recognized the duty to serve as it applies to these industries.[22] But, exclusive reliance on courts to enforce the duty was becoming unworkable for a number of reasons including the cost of litigation, companies' reliance on settlements to avoid adverse precedents, and courts' institutional inadequacy at defining and enforcing "reasonable" rates.[23] Statutes such as the Interstate Commerce Act sought to address this by more clearly establishing the obligations of these public interest-

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13. *Id*. at 1244-46.

14. *Id*. at 1244. In return, customers requiring such services may be required to use those services rather than those of a third party—e.g. requiring "all inhabitants of the medieval manor to grind all grain at the lord's mill." *Id*.

15. Rossi, *supra* note 2, at 1246.

16. *Id*.

17. *Id*. at 1246-48.

18. 94. U.S. 113, 125-26 (1877).

19. 291 U.S. 502, 536 (1934).

20. *Id*.

21. Rossi, *supra* note 2, at 1248-49.

22. *Id*.

23. *Id*. at 1250.

affected businesses, and eventually states established regulatory agencies to define and enforce these obligations outside of the judicial system.[24]

Under this regulatory system, these agencies—typically known as public utility commissions (PUCs) or public service commissions (PSCs)[25]—enforce a version of the following: utilities are granted a utility franchise (i.e. monopoly) to provide safe and adequate service to all interested parties in a particular service territory.[26] In return, the PUC has the authority over the rates a utility charges its customers, which must be just and reasonable.[27] Every state now has a statute in place defining the duty to serve.[28] Some of these statute are explicit in invoking utility's duty; Alabama's statute, for example, states that "[e]very utility shall render adequate service to the public and shall make such reasonable improvements, extensions and enlargements of its plants, facilities and equipment as may be necessary to meet the growth and demand of the territory which it is under the duty to serve."[29] In other states, the statute focuses on the PUC's authority and responsibilities. For instance, Georgia law states that "[t]he commission may, either by general rules or by special orders in particular cases, require all companies under its supervision to establish and maintain such public services and facilities as may be reasonable and just."[30]

Housed within the overarching framework of nondiscriminatory service in exchange for just and reasonable rates set by each of these state laws are the obligations of utilities to connect and serve new customers.[31] Regardless of the specific statutory formulation, by the end of the 20th century the duty to serve was generally regarded as containing three related obligations: (1) an obligation to extend service to new customers within the service territory, (2) an obligation to provide service that is adequate, and (3) an obligation to continue providing that service.[32] None of these obligations is limitless, with lawmakers, regulators, and courts all weighting in at different times to define when these obligations apply

24. *Id*.

25. Other titles include "corporation commission," "board of public utilities," and "department of public utilities" to name a few. *See Public Utilities Commissions*, COMPARE POWER (last visited Sep. 15, 2025), https://comparepower.com/public-utility-commissions/.

26. Bagdanov, *supra* note 1, at 6.

27. *Id*.

28. *See id*. at 23-36; Heathery Payne, *Unservice: Reconceptualizing the Utility Duty to Serve in Light of Climate Change*, 56 U. Rich. L. Rev. 603, 660-61 (2022).

29. ALA. CODE § 37-1-49 (2025).

30. GA. CODE ANN. §46-2-20(c) (2025).

31. State laws vary in how it describes this nondiscrimination requirement, with some statutes stating that service must be "nondiscriminatory" or "without discrimination", while others prohibit utility actions that are "unjustly" or "unduly" discriminatory. *See* D.C. CODE §1-204.93 (2025); 220 ILL. COMP. STAT. 5/8-101 (2025); WYO. STAT. ANN. § 37-3-112 (2025); KAN STAT. ANN. § 66-101(b) (2025). As a practical matter, a "nondiscriminatory" standard still accommodates a degree of reasonable discrimination among customers; for example, utilities may still sort customers into different rate classes based on relevant shared characteristics.

32. Rossi, *supra* note 2, at 1243 ("As applied today in most states, the public utility duty to serve entails several obligations, among them duties to interconnect and extend service if requested, to provide continuing reliable service, to provide advanced notice of service disconnection, and to continue service without full payment."); *See also The Duty of a Public Utility to Render Adequate Service: Its Scope and Enforcement*, 62 COLUM. L. REV. 312, 313-22 (1962) [hereinafter *Duty of a Public Utility*] (discussing the obligation to render service to customers, the scope of adequacy of service, and the requirements related to abandonment of service).

and the qualifications utilities can place on meeting them. The general formulation of the duty to serve, however, remains very much alive in statutory language and PUC decisions nationwide.

B. Prudence and Used-and-Useful Tests

Often alongside, and at times in tension with, the duty to serve are the requirements that a utility's investments be "prudent" and "used-and-useful" to be eligible for cost recovery. Prudence is a backwards-looking analysis that seeks to determine whether the utility's decision-making was reasonable given the information available at the time it made those decisions.[33] Used-and-useful, in contrast, is a present-oriented analysis to determine whether a utility investment is actually serving customers (used) and is providing benefits to those customers by lowering costs or increasing service quality (useful).[34]

In fulfilling these expectations, utilities must balance the need to minimize costs with the duty to serve customers safely and reliably. Utilities could spend significantly more money than they do today to make their systems as safe and reliable as possible, but this would come at the expense of enormous increases in the rates customers must pay for service, which may render such investments imprudent. Conversely, the utility could cut investment drastically. This would reduce customers' rates but risks degrading system reliability and safety, thereby violating the utility's duty to serve. PUCs apply these tests as part of their consideration of utilities' requested rates to ensure that customers are benefitting from reasonable utility investments before paying for those investments. Utility regulators generally presume a utility's investments to be used and useful and prudent unless presented with evidence to the contrary.[35]

These competing obligations are also complicated by the fact that many utility investments are necessarily "lumpy." That is to say, utilities often cannot practicably or cost-effectively increase service by only the marginal amount a customer requests by building *just enough* generation, transmission, and distribution

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33. Jim Lazar et al., *Electricity Regulation In the US: A Guide*, REGUL. ASSISTANCE PROJECT, at 31 (2d. ed. 2016), https://www.raponline.org/wp-content/uploads/2023/09/rap-lazar-electricity-regulation-US-june-2016.pdf ("Once a power plant or other capital project is completed, the commission may conduct a prudence review to determine if it has been constructed or implemented as proposed, according to sound management practices, and at a reasonable cost and with reasonable care.").

34. *Id*. at 50 ("In general, used means that the facility is actually providing service, and useful means that without the facility, either costs would be higher or the quality of service would be lower."); *see also* James J. Hoecker, *Used and Useful: Autopsy of a Ratemaking Policy*, 8 ENERGY L.J. 303, 310 (1987) ("The corpus of regulatory and court opinion prescribes that a utility's operating expenses may not be recovered in rates and that even prudently-incurred costs of plant will not be included in rate base, unless a benefit from such expenditures inures to the benefit of present ratepayers."). While the used-and-useful test is still widely employed, however, it is not dispositive. In *Jersey Central Power & Light Co. v. FERC*, the D.C. Circuit found that regulators' ultimate focus must be on whether a rate and the cost recovery it allows for is just and reasonable, and while "not precluded from employing 'used and useful,' or any other specific rate-setting formula" these formulas cannot form an "impregnable barrier" to utilities' cost recovery requests. 810 F.2d 1168, 1187 (D.C. Cir. 1987).

35. Lazar et al., *supra* note 33, at 50-52.

infrastructure to serve that customer.[36] A utility's investments in new wires, transformers, and substations usually require it to add capacity in larger blocks than an individual customer may require.[37] Historic application of the prudency and used-and-useful tests recognize this practical necessity. When a utility brings a new substation into service, for example, it typically won't enter service at full capacity but rather will have excess "headroom" available to serve additional load growth. Such headroom, even if not strictly needed in the immediate term, may nevertheless be deemed used-and-useful where it enhances system flexibility or reliability, or serves as a reasonable hedge against changing future needs. In fact, a new substation that enters service already at full capacity may signal significant errors in the utility's forecasting and planning.[38] The balance for utilities and their regulators to strike, then, is finding the appropriate amount of headroom to plan for as part of any investment to minimize long-term costs while ensuring safety and reliability.

III. CURRENT CONTEXT OF END-USE ELECTRIFICATION

The U.S. is quickly exiting a relatively stable era of electricity consumption. The last two decades have seen enormous changes in electricity generation, most notably the decline of coal and the rise of renewables and fossil gas.[39] But in the midst of these changes, the total amount of electricity delivered to customers has barely shifted. After seeing steady growth in demand between 1950 and 2005, the trendline has been almost flat in the twenty years since, largely due to improved energy efficiency in both the industrial and residential sectors.[40] Now, however, all signs point to the country leaving this interglacial period of steady demand and entering an era of uncertain but robust load growth. This new load growth is being driven by three main factors:

- End-use electrification, which refers to the electrification of end uses that have historically relied on fossil fuels, driven by both economic factors and policies around decarbonization. This includes

36. William J. Baumol & J Gregory Sidak, *The Pig in the Python: Is Lumpy Capacity Investment Used and Useful?*, 23 ENERGY L.J. 383, 385 (2002) ("A utility, for example, cannot add one kilowatt of generation capacity at a time, but rather must add all of the capacity inherent in a single generator or a single power plant.").

37. Some smaller investments are available that can allow for more marginal increases in available capacity in certain circumstances. Voltage regulators, for example, can be used to address unacceptable drops in voltage resulting from new interconnections along a circuit, rather than requiring an upgrade to the entire circuit's wiring. *See Voltage Regulators: Fundamental of Power Distribution Voltage Regulators*, EATON (last visited Sep. 15, 2025), https://www.eaton.com/us/en-us/products/medium-voltage-power-distribution-control-systems/voltage-regulators/voltage-regulators--fundamentals-of-voltage-regulators.html. But solutions like this are only available to address specific system limitations (voltage regulators can't prevent a circuit from exceeding its thermal limits), and eventually equipment must be upgraded or expanded.

38. *See* Baumol & Sidak, *supra* note 36, at 385-86 (explaining how during periods of growing demand, "even in a world of perfect certainty about the future and zero lag in plant construction, the so-called excess capacity becomes an inescapable feature of the obligation to serve customers.")

39. *Electricity Explained: Electricity in the United States*, U.S. ENERGY INFO. ADMIN. (Mar. 26, 2024), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php.

40. *Id.*; Bouckaert & Goodson, *supra* note 3.

the electric vehicles, which displace gasoline and diesel consumption;[41] electrification of space and water heating, which displace fossil gas, propane and heating oil;[42] and electrification of industrial processes, which displace oil, gas, and coal;[43]

- Industrial load growth, including new and expanding processing and manufacturing work driven by a number of factors including policy goals and economic realignment resulting in "onshoring" of industries;[44] and
- Data center load growth, with artificial intelligence-driven load expected to accelerate the existing growth trend for non-AI data centers.[45] Cryptocurrency mining represents a related category of energy-hungry data processing with uncertain, potentially significant load growth that is particularly mobile.[46]

There is not yet consensus regarding which of these categories of load will be the largest driver of new electricity demand,[47] and uncertainty over federal policy regarding both data centers and end-use electrification is likely to cloud the picture further.

This load growth coincides with a renewed focus on electricity affordability. Years of rising electricity rates, and corresponding increases in customer arrears and disconnects for unpaid bills,[48] put pressure on regulators to control rate increases by restricting utility spending. To this end, shrinking utility investments

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41. *See* Vandana Gombar, *Electric Cars Have Dented Fuel Demand. By 2040, They'll Slash It*, BLOOMBERGNEF (Aug 15, 2023), https://about.bnef.com/blog/electric-cars-have-dented-fuel-demand-by-2040-theyll-slash-it/.

42. *See Heat Pump Impact Evaluation Final Report*, DNV, at 9 (Apr. 2022), https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/PPSER/Program-Evaluation/Heat-Pump-Impact-Evaluation-Report-August-2022.pdf.

43. *See* Daniel Steinberg et al., *Electrification & Decarbonization: Exploring U.S. Energy Use and Greenhouse Gas Emissions in Scenarios with Widespread Electrification and Power Sector Decarbonization,* NAT'L RENEWABLE ENERGY LAB., at 2 (2017), https://www.nrel.gov/docs/fy17osti/68214.pdf ("By substituting the use of fossil fuels, including coal, natural gas, and petroleum-based fuels, with (increasingly) lower carbon intensity generation sources, electrification and power system decarbonization can reduce emissions associated with fossil fuel combustion in end-use sectors.").

44. *See Reindustrialization, Decarbonization, and Prospects for Demand Growth*, EPRI (July 2023), https://interactive.epri.com/reindustrialization-growthdemand-2023/p/1.

45. *See* Wilson et al., *supra* note 5, at 10 (estimating data center load growing to nearly 10% of total U.S. electric load by 2029, with AI load representing 70% of new data center load).

46. *Tracking Electricity Consumption, supra* note 4.

47. Some forecasts suggest data centers will be the primary source of new load in the coming years. *See id*. at 3 (forecasting between 65 to over 90 gigawatts of new demand in the next five years, compared to 20 gigawatts each for manufacturing, and other load including electrification). Other forecasts are more bullish on electrification load growth and conservative on data center load. *See* Ben King et al., *Taking Stock 2024: US Energy and Emissions Outlook*, RHODIUM GRP., at 26 fig. 13 (July 23, 2024), https://rhg.com/research/taking-stock-2024/ (forecasting that data centers will be responsible for 22% of new electricity consumption by 2035, with transportation electrification alone outpacing data centers before 2030 and reaching 46% of new electricity consumption by 2035).

48. *See* Akielly Hu, *Rising Utility Bills Have Americans Worried*, CANARY MEDIA (Apr. 23, 2025), https://www.canarymedia.com/articles/utilities/rising-gas-electric-bills-survey; Akielly Hu, *Utilities Are Shutting Off Power to a Growing Number of Households*, GRIST (Mar. 18, 2025), https://grist.org/climate-energy/utilities-are-shutting-off-power-to-a-growing-number-of-households/.

can be counterproductive: as discussed further below, distribution system investments can mitigate or reverse rate increases where those investments spread utility costs across increased electric sales, as is commonly the case with infrastructure that supports vehicle electrification.[49] But evaluating such impacts, and incorporating them into regulatory decisions, adds a further layer of complexity in an already-fraught moment.

While each of the above drivers are expected to significantly contribute to overall load growth, end-use electrification has two key characteristics that differentiate it from data center and industrial loads. The first is end-use electrification's reliance on utilities' distribution systems. While some of this load, such as large EV charging sites and electrifying industrial loads, may connect at the transmission or sub-transmission level, much of it will rely on connections to the distribution system at primary or secondary voltages.[50] This includes smaller EV charging depots, destination charging, and most residential customers. This means that utilities should expect to serve this load all the way to the lowest levels of their systems. This also means that end-use electrifying loads will generally pay for a share of distribution, transmission, and generation costs through their utility's tariff, which may not be true for data centers connecting at the transmission level or directly to generators.[51]

Second, end-use electrification loads tend to have lower load factors, and higher load diversity factors, than industrial and data center loads, and are therefore likely to have smaller impacts on generation and transmission needs.[52] Data centers and industrial customers tend to have high load factors, meaning they have

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49. *See* Joint Compliance Filing of Southern California Edison Company (U 338-E), San Diego Gas & Electric Company (U 902 E) and Pacific Gas and Electric Company (U 93 E) Pursuant to Ordering Paragraph 2 of Decision 16-06-011, Rulemaking 23-12-008, at Attachment 1, 21-22, 41 (Cal. Pub. Utils. Comm'n Apr. 2, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K073/529073552.PDF [hereinafter Joint Compliance Filing] (showing the load profile for an average residential EV charging customer peaking overnight, and the load profile for the average fleet EV charging customer peaking midday and overnight). Energy affordability is likely to continue to be a key issue not just for utilities and PUCs, but also state and federal lawmakers as the overlapping trends of load growth, an aging grid, and political conflicts over energy policy continue. *See* Brad Plumer & Rebecca F. Elliott, *Electricity Prices Are Surging. The G.O.P. Megabill Could Push Them Higher*, N.Y. TIMES (June 4, 2025), https://www.nytimes.com/2025/06/04/climate/electricity-prices-republican-big-beautiful-bill.html?searchResultPosition=6.

50. National Grid New York, for example, connects customers with demand of less than 5 MW at distribution voltages, and at least considers higher-voltage connections for customers over this threshold. Gideon Katsh et al., *Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation*, NAT'L GRID, at 31 (Nov. 2022), https://www.nationalgrid.com/document/148616/download.

51. *See* Eliza Martin & Ari Peskoe, *Extracting Profits from the Public: How Utility Ratepayers Are Paying for Big Tech's Power*, HARV. L. SCH. 16-21 (Mar. 2025), https://eelp.law.harvard.edu/wp-content/uploads/2025/03/Harvard-ELI-Extracting-Profits-from-the-Public.pdf (discussing how data centers connecting at the transmission level can shift costs they cause onto other ratepayers).

52. Load factor is a measure of a customer's average electric load divided by their maximum load. For example, a customer with a peak load of 10 kW and an average load of 2 kW would have a load factor of 0.2. Load diversity factor, or simply diversity factor, refers to the sum of individual noncoincident maximum loads divided by the maximum coincident load. For example, a group of EV fleets may have individual maximum loads that add up to 1 MW, but because they charge at different times of day their coincident peak load is 500 kW. Their load diversity factor would be 0.5. *See* Jignesh Parmar, *Energy Demand Factor, Diversity Factor, Utilization Factor, and Load Factor*, ELEC. ENG'G PORTAL (last updated Oct. 28, 2024), https://electrical-engineering-portal.com/demand-factor-diversity-factor-utilization-factor-load-factor.

relatively consistent electric usage, and collectively their grid capacity needs at their points of interconnection are similar to the capacity needs they create at the transmission and generation level,[53] though there may be more variability in power consumption for AI data centers in particular.[54] In contrast, loads like EV chargers or heat pumps do not run continuously. A commercial area may host several fleets of EVs, some of which charge overnight while others charge opportunistically throughout the day. Each of those fleets may need a distribution transformer capable of serving their individual maximum charging load, but the utility may not need the transmission or generation capacity to serve their collective charging load simultaneously because it is diversified.[55] This means that end-use electrification load can require significant work to prepare their distribution grid for those utilities that experience the greatest demand growth from these customers, while at the same time potentially seeing a slower pace of upgrade and expansion needs at the transmission and generation level.[56]

Although their load growth impacts may focus on different portions of the grid, collectively the coming load growth from end-use electrification, data centers, industrial loads, and more will all compete for utilities' limited attention and capacity to complete the analytical, engineering, construction work necessary to interconnect a customer. The scale of this need is significant. In California, where end-use electrification is forecast to be a large driver of distribution-level load growth,[57] estimates range from $8 to $57 billion in grid upgrades needed by 2035 to serve end-use electrification load growth.[58] In New York, the New York State

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53. Isabelle Riu et al., *Load Growth is Here to Stay, but Are Data Centers?*, ENERGY AND ENV'T ECON. 20 (July 2024), https://www.ethree.com/wp-content/uploads/2024/07/E3-White-Paper-2024-Load-Growth-Is-Here-to-Stay-but-Are-Data-Centers-2.pdf (estimating data center load factors to average 86%).

54. Ryan Quint et al., *Practical Guidance and Considerations for Large Load Interconnections*, GRIDLAB 20 (2025) (discussing how data centers used to train AI models can have "extremely intermittent power consumption" with power consumption jumping by tens of megawatts in less than one second).

55. *See Staff Proposal, supra* note 8, at 37-38 (explaining how adding up non-coincident peaks of EV charging stations can overestimate generation capacity needs).

56. *See* Paul Hibbard et al., *Heavy Duty Vehicle Electrification: Planning for and Development of Needed Power System Infrastructure*, ANALYSIS GRP. 15-16 (June 2023), https://www.analysisgroup.com/globalassets/insights/publishing/2023-hibbard-heavy-duty-vehicle-electrification.pdf (finding that a 2023 proposed rule from the U.S. Environmental Protection Agency regarding heavy-duty vehicle emissions would likely increase electrification but would likely not have driven challenges for power generation or transmission).

57. Load forecasts from the California Energy Commission do not separate residential electrification—e.g. space and water heating electrification—from other residential loads but do include specific forecasts for transportation electrification. *See* CAL. ENERGY COMM'N, *California Energy Demand Forecast: 2023 - 2040 Baseline Forecast* (Jan. 2024), https://efiling.energy.ca.gov/GetDocument.aspx?tn=254253&DocumentContentId=89618 (estimating that electricity consumption from electric vehicles will grow from less than 2% of total statewide consumption in 2025 to nearly 13% in 2040).

58. *See* PUB. ADVOC. OFFICE, *Distribution Grid Electrification Model*, at 43 (August 2023), https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/press-room/reports-and-analyses/230824-public-advocates-distribution-grid-electrification-model-study-and-report.pdf [hereinafter *Electrification Model*] ("We estimated the cost of upgrades to be $26 billion. This number has significant uncertainty and could be as much as $18 billion lower or $31 billion higher based mainly on the unit costs of upgrades."); *see also* KEVALA, *Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates*, at ES-6 (May 9, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K423/508423247.PDF [hereinafter *Electrification Impacts Study*] ("Across these

Energy Research and Development Authority estimated that preparing the state's distribution systems for EV charging alone would require between $1.4 and $26.8 billion through 2050, depending on the charging assumptions used.[59]

Utilities will need to upgrade existing infrastructure, including expanding substations and converting circuits to higher voltages, while also building new assets in high-demand areas. This work takes time, as utilities navigate the permitting, property acquisition, engineering, and construction processes before a new piece of infrastructure can begin serving customers. The longer and more complex this process, the more it implicates the boundaries of utilities' duty to serve their customers, as long delays or insufficient grid capacity can stymie customers' ability to energize in line with policy goals, individual commitments, and economic realities. Without sufficient, timely utility service, some customers may have the resources to self-supply a portion of their electricity needs — e.g., through zero-emission distributed energy resources such as solar and battery storage, or polluting sources such as diesel and fossil gas generators.[60] But where such alternatives are financially or technically infeasible, customers have little choice but to stick to the status quo of fossil fuels consumption. This places utilities in the position of operating in a competitive environment within their own service territory,[61] and creates a potential for entrenchment of fossil fuel consumption. Ensuring utilities' investment decisions and operations are supportive of, rather than a hindrance to, end-use electrification is therefore essential to avoid utilities becoming a barrier to the energy transition.

IV. DUTY TO SERVE IN THE CURRENT ERA

Today, utilities' duty to serve can generally be thought of as encompassing three interlocking obligations: 1) an obligation to connect new customers within a utility's service territory, 2) an obligation that the provided service be "adequate" in meeting the needs of customers, and 3) an obligation to continue providing that

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unmitigated load scenarios, Kevala estimates up to $50 billion in traditional electricity distribution grid infrastructure investments by 2035").

59. RES. INNOVATIONS, *Transportation Electrification Distribution System Impact Study*, at ES-2 (May 2022), https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Transportation/22-13-Transportation-Electricification-Distribution-System-Impact-Study.pdf ("The NPV of New York State's distribution system upgrade costs due to transportation electrification range from $1.4 billion in the LDI Managed EV charging case to $26.8 billion in the HDI Unmanaged case.").

60. In the most extreme cases, larger customers such as data centers are also funding efforts to restart mothballed nuclear power plants to meet their electricity needs. *See* Brian Martucci, *Constellation Plans 2028 Restart of Three Mile Island Unit 1, Spurred by Microsoft PPA*, UTILITYDIVE (Sep. 20, 2024), https://www.utilitydive.com/news/constellation-three-mile-island-nuclear-power-plant-microsoft-data-center-ppa/727652/.

61. Competition between regulated utilities, or between a regulated utility and an unregulated entity, is not unprecedented, as competition between electric utilities, gas utilities, and trucked fuel providers (e.g. propane and home heating oil) has taken place in different forms since the earliest days of electric utilities. *See* Joshua Lappen et al., *The Unseen Competition in the Energy Transition: Acknowledging and Addressing Inter-Utility Competition to Achieve Managed Decarbonization*, STAN. WOODS INST. FOR THE ENV'T., at 5-8 (Sep. 2024), https://woods.stanford.edu/sites/woods/files/media/file/woods-energy-transition-white-paper-v06-web.pdf.

service.[62] These obligations are not absolute, though they typically set a high bar for utilities. For example, regulators can generally require utilities to make all "reasonable" extensions of service to new customers within the service territory, excusing only those extensions where the cost of providing service is "disproportionate to the overall expected return to the utility in accommodating the new customer."[63] It is not enough that an extension may be unprofitable for a utility, so long as the extension can be made "without harming current customers."[64] Similarly, regulators typically allow utilities to shut off service to customers for nonpayment of their utility bill, though this can be constrained by the imposition of certain requirements prior to shutoff,[65] or halted entirely through moratoria like those put in place in many states during the early stages of the COVID-19 pandemic.[66]

Over the more than a century since the adoption of the duty to serve into American law and the development of the modern utility regulatory framework, the topic has been a relatively quiet corner of utility scholarship and jurisprudence. There have been, however, two recent waves of academic discourse on the implications of the duty to serve during times of significant change in the utility business. The first, around the turn of the 21st century, centered on the meaning of the duty to serve during a time of deregulation of electricity generation and growth of retail competition.[67] Faced with the prospect of utilities moving electricity through their wires that they themselves did not generate, this scholarship considered the origins of the duty to serve,[68] analogous duties applied to other industries,[69] and the goals of utility restructuring,[70] to recommend what regulators should still require of utilities in providing service to customers.[71]

A second wave, one that is still ongoing, focuses on tensions between the obligation to serve and climate change mitigation and adaptation efforts. This

62. Rossi, *supra* note 2, at 1243 ("As applied today in most states, the public utility duty to serve entails several obligations, among them duties to interconnect and extend service if requested, to provide continuing reliable service, to provide advanced notice of service disconnection, and to continue service without full payment."); *See also Duty of a Public Utility*, *supra* note 32, at 313-322 (discussing the obligation to render service to customers, the scope of adequacy of service, and the requirements related to abandonment of service).

63. Rossi, *supra* note 2, at 1253.

64. *Id*. at 1256.

65. *See generally Disconnect Policies*, LIHEAP CLEARINGHOUSE (last updated Aug. 1, 2025), https://liheapch.acf.hhs.gov/Disconnect/disconnect.htm (detailing utility disconnect policies across the U.S.).

66. Jennifer Andre et al., *The Effects of State Utility Shutoff Moratoria on Credit Delinquencies During the COVID-19 Pandemic*, 129 J ECON. & BUS. 106170 (2024) (detailing the location and duration of utility shutoff moratoria across the U.S. in response to the COVID-19 pandemic).

67. *See generally* Rossi, *supra* note 2; Roger D. Colton, *The "Obligation to Serve" and a Competitive Electric Industry*, OAK RIDGE NAT'L LAB'Y (Nov. 1997), https://weatherization.ornl.gov/wp-content/uploads/pdf/1996_2000/ORNL_CON-459.pdf.

68. *See* Rossi, *supra* note 2, at 1244-60.

69. *See* Colton, *supra* note 67, at 5-11.

70. *See* Rossi, *supra* note 2, at 1280-87.

71. Colton, *supra* note 67, at 40-70 (discussing the obligation to connect customers, to provide service to residual classes, to make a standard offer, to provide non-discriminatory service, and to fund residual markets in the context of a restructured electricity market); Rossi, *supra* note 2, at 1288-89 (recommending the taxing of power consumption or supply to "continue financing the duty to serve" in competitive power markets).

includes work on how utilities and regulators should harden the grid against extreme weather impacts and how they should consider when and how to disconnect customers, or decline to reconnect customers, in the face of extreme weather and climate impacts.[72] It also includes efforts to spur building decarbonization through reducing or eliminating customers' fossil gas consumption, which presents tensions with gas utilities' obligation to serve customers requesting new gas service.[73] This scholarship attempts to address the situations where utilities should be allowed, or required, to cease providing services to certain customers as part of efforts to mitigate and/or adapt to the effects of climate change.[74] Some have also begun to consider what the duty to serve means for connecting to the grid new large loads like data centers, including whether and how it may threaten reliability, delay the retirement of fossil fuel generation, and drive up rates for other customers.[75] The appropriate regulatory responses to these concerns may require more fundamental considerations of the proper scope and definition of the duty to serve than what is at issue in this article.

There has not been a similar legal academic focus on what the duty to serve means for utilities' affirmative obligations in the face of end-use electrification at the distribution level, or how regulators should apply the obligation to this electric load growth in particular. On its face, it may appear that the current, simple formulation of the duty to serve is already of sufficient benefit to customers with new

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72. *See* Payne, *supra* note 28; Jim Rossi & Michael Panfil, *Climate Resilience and Private law's Duty to Adapt*, 100 N.C. L. Rev. 1135 (2022); Janice A Beecher et al., *Regulatory Imperative to Ensure Utility climate Resilience Planning*, 45 Energy L. J. 83 (2024).

73. *See* Bagdanov, *supra* note 1; Nicholas Wallace et al., *Removing Legal Barriers to Building Electrification*, STAN. WOODS INST. FOR THE ENV'T (2020), https://law.stanford.edu/wp-content/uploads/2020/10/2020-10-20_Natural-Gas-Memo_formatted.pdf; *see also* Justin Gundlach & Elizabeth B. Stein, *Harmonizing States' Energy Utility Regulation Frameworks and Climate Laws: A Case Study of New York*, 41 Energy L. J. 211 (2020).

74. *See, e.g.*, Payne, *supra* note 28, at 645-46 (discussing how in certain circumstances, such as an extreme weather event knocking out service to vulnerable properties, regulators should consider modifying the duty to serve by removing certain properties from utilities' service territories and preventing other utilities from providing those services.); Bagdanov, *supra* note 1, at 21 (recommending that regulators remove the obligation to extend service from gas utilities' duty to serve).

75. *See, e.g.*, Walton Shepherd, *VA's Data Center Talk Must Get Real to Meet Big Tech's Climate Goals*, NAT. RES. DEF. COUNCIL (Dec. 14, 2024), https://www.nrdc.org/bio/walton-shepherd/vas-data-center-talk-must-get-real-meet-big-techs-climate-goals ("For starters, a utility's duty to serve is not an all-consuming monolith that swamps all other considerations: that principle of fairness exists equally alongside other bedrock regulatory principles embodied in Virginia's statute."); Yoon Kim, *Connecting Data Centers to the Grid: An Innovative and Controversial Proposal from AEP Ohio*, CLIMATE L.: GUEST BLOG (Sep. 12, 2024), https://blogs.law.columbia.edu/climatechange/2024/09/12/guest-blog-connecting-data-centers-to-the-grid-an-innovative-and-controversial-proposal-from-aep-ohio/ ("Most states have similar statutory language to Ohio regarding the duty to serve all customers in a reasonable and non-discriminatory manner. The Ohio proceeding will be the first to decide how those century-old provisions apply to the novel issue of data center growth and what leeway public utilities may have for treating data centers differently."); Severin Borenstein, *Is there a "Duty to Serve" Hyperscale Loads?*, ENERGY INST. AT HAAS: ENERGY INST. BLOG (Dec. 2, 2024), https://energyathaas.wordpress.com/2024/12/02/is-there-a-duty-to-serve-hyperscale-loads/ ("Does non-discriminatory duty to serve mean that a new hyperscale customer has as much right to demand reliable power at any hour of the year as an incumbent customer?"); *see also* Martin & Peskoe, *supra* note 51. The Ohio PUC finalized its Data Center Power tariff in July 2025. *See* In the matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers, No. 24-508-EL-ATA, (Ohio Pub. Utils. Comm'n July 9, 2025), https://dis.puc.state.oh.us/ViewImage.aspx?CMID=A1001001A25G09B43531I00509.

or increasing demand. So long as those customers are within a utility's service territory, and serving those customers would not result in significant financial harm for the utility, the utility must connect the customer to the grid and perform the necessary system work to serve them and existing customers safely and reliably. But, as is already evident in jurisdictions seeing significant end-use electrification load growth, utilities struggle to connect new loads to their systems at a pace and manner necessary to meet customer needs or policy goals. In California, where utilities are already facing significant demand for grid capacity to support end-use electrification, some customers are facing delays of several years before they can interconnect if that interconnection requires a grid upgrade.[76] These challenges will not be exclusive to California, as end-use electrification is broadly expected to drive significant load growth on distribution grids across the U.S.[77] In response, regulators in some states have begun to recognize the need for more proactive forecasting and planning efforts to prepare the grid in advance of this load, rather than in response to specific customer interconnection requests.[78] This shift is critical to ensuring utilities meet their legal obligation to customers, and represents an updated vision of the duty to serve adapted to supporting states' end-use electrification goals: *building and maintaining a grid with sufficient excess capacity at the right time in the right places to interconnect a customer requesting service, without threatening the safety and reliability of the system as a whole*. The remainder of Part III considers how to effectuate this form of the duty to serve to remove barriers to end-use electrification.

A. Anticipating Future Loads

Key to serving new electric load is first having a reasonably accurate forecast of when and where that new load will connect to the grid. While no forecast can perfectly predict this future demand, having a reasonably accurate forecast is necessary both to ensure sufficient generation, transmission, and distribution infrastructure is available to serve future load, and to avoid unnecessarily overbuilding

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76. *See* Opening Comments of Powering America's Commercial Transportation on the Administrative Law Judge's Ruling Directing Parties to Respond to Questions on Energization Issues, Rulemaking No. 24-01-018, at 6 (Cal. Pub. Utils. Comm'n June 18, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M534/K105/534105479.PDF [hereinafter Opening Comments] ("PACT members have shared anecdotal information regarding utility responses to 2-5 MW projects in Southern California, noting that these requests are frequently quoted an energization date into 2029. Most of those projects are then put on hold, postponed, or canceled because of this lengthy energization timeline.").

77. *2024 Long-Term Reliability Assessment*, N. AM. ELEC. RELIABILITY CORP., at 32 fig. 19 (last updated July, 15 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf (identifying transportation and/or building electrification as a "primary driver" of load growth in six of the thirteen U.S. Assessment Areas).

78. *See* Opening Comments, *supra* note 9; *see also* Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure and Closing Rulemaking 18-12-006, Rulemaking No. 18-12-006, at 9 (Cal. Pub. Utils. Comm'n Dec. 20, 2023), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K872/521872957.PDF (finding that "in addition to improving the response process to customer requests for electric vehicle charging energization, the increased pace and scale of the distribution and transmission infrastructure needed to support this transition will require reforms to grid planning as they relate to transportation electrification. This may include improved early identification of future transportation electrification load to support existing electric grid planning processes . . . .").

and driving up customers' bills. End-use electrification can be expected to impact future loads in ways that don't align with historical load growth trends, and will require utilities to adapt their forecast assumptions and methods to ensure they aren't caught unprepared to serve this load when customers are ready to electrify.

The right and duty of a public utility to adequately prepare to serve future loads is not a new concept within the duty to serve. More than a century ago in *Northern Light & Power Co. v. Stacher*, a group of property owners challenged a utility's eminent domain action to take water rights as part of the development of a hydroelectric facility.[79] The owners argued that the utility hadn't met the requirement that it show the taking to be "necessary" because it did not specify in its filing that meeting the needs of its customers would require more electric capacity than it could supply with existing infrastructure.[80] The California Court of Appeals disagreed, finding that public utilities "have a right and it is their duty to anticipate future needs of the public" and "cannot reasonably be required to limit their preparations for future demands by their ability to provide for them out of their present supply."[81] The court expressed a prescient view of electric load growth and the difficult job for utilities of forecasting and serving that growth:

> New uses for electricity are constantly being discovered and applied. The supply which in the same community would at present be sufficient might be insufficient in a short time. Nor can public service corporations state with certainty to what extent their facilities to serve the public will be availed of. Neither can they determine, nor should they be required to determine in advance, and set forth in their complaint that their present equipment is insufficient to meet the needs of the people.[82]

The utility is not absolved from the requirement to provide evidence that that property at issue is available, appropriate, and necessary to meet the identified public need, but the court saw these as evidentiary questions, not legal ones.[83]

The California Supreme Court built on this in *Lukrawka v. Spring Valley Water Works*, articulating not just the power of a public utility to prepare for future demand, but the obligation to do so.[84] There, Spring Valley Water Works held the utility franchise to provide drinking water to the city and county of San Francisco. The plaintiffs, a group of homeowners in the city, sued the utility to extend its service to their streets after it refused to do so. The court was clear that the utility's duty to serve encompassed preparing for, and serving, reasonably anticipated growth in demand:

> The proper discharge of this public duty required not only that the company should provide a supply of water and establish a system for its distribution to meet the reasonable needs of the municipal community as it then existed, but it was under the obligation to keep in view the prospective and probable increase in population of the municipality and the necessarily increasing demand for a water supply which would be consequent therefrom; to anticipate the natural growth of the municipality it had undertaken to serve as a whole and to take

79. 109 P. 896 (Cal. Dist. Ct. App. 1910).

80. *Id*. at 902-03.

81. *Id*.

82. *Id*. at 903.

83. *N. Light & Power Co*., 109 P. 896, 903 (Cal. Dist. Ct. App. 1910).

84. 169 Cal. 318, 146 P. 640 (1915).

> reasonable measures to have under its control a sufficient supply of water and make gradual extensions of its distributive system to meet the reasonable demands for water by the growing community.[85]

There are key similarities and differences between the electric load growth seen today and the growth demanded of electric and drinking water systems in the early 20th century that these courts were responding to. Given the scale of the demand, both periods would require utilities to prepare their systems in advance rather than simply waiting for individual customer requests. But, whereas the utility systems of a century ago were largely seeing demands to expand their geographic footprints through extension of service to new areas within their franchise territory, much of the load growth seen on electric distribution systems today is happening within areas where service is already available and requires new or upgraded infrastructure where utility assets already exist today. Furthermore, the tools available to utilities today to forecast this load growth are orders of magnitude more sophisticated than those of a century ago, with new techniques, new technologies, and new data sources all available to improve the usefulness of load forecasts.[86]

The accuracy of load forecasting is constrained by both the uncertainty of the factors driving changes in load, and the limitations of utilities' capacity for data collection and analysis. By the late 20th century and into the 21st, load forecasting methods for distribution utilities largely sought to estimate future load at the level of an individual piece of equipment over a short time horizon (<five years), while using a broader geographic scale for long-term forecasts.[87] These long-term forecasts have traditionally been top-down models, which estimate future load at the service territory scale or a similar large area, and then disaggregate that figure downwards to estimated expected loads on equipment such as substations, feeders, and transformers.[88] Top-down models have the advantages of being efficient to produce and supporting consistent assumptions across a utility's operations, but can lack geographic precision because it cannot reflect heterogeneity of impacts at various locations on the utility's system.

85. *Id*. at 325.

86. *See* U.S. DEP'T ENEERY, GUIDANCE DOCUMENT ON SPACE HEATING ELECTRIFICATION FOR LARGE COMMERCIAL BUILDINGS WITH BOILERS, at viii (Apr. 2024), https://www.energy.gov/sites/default/files/2024-04/Large%20Building%20Boiler%20Electrification%20Guidance.pdf [hereinafter GUIDANCE DOCUMENT]; Sean Morash, *Grid Planning for Building Electrification*, ENERGY SYS. INTEGRATION GRP., at 14 (Oct. 2024), https://www.esig.energy/wp-content/uploads/2024/10/ESIG-Grid-Planning-Building-Electrification-report-2024.pdf ("While utilities have time to plan for new building developments and industrial facilities, individual building retrofits can happen virtually overnight and without warning."); *see also* Daniel D. Slate et al., *Adoption of Artificial Intelligence by Electric Utilities*, 45 ENERGY L .J. 1, 10 (2024) (discussing the potential of artificial intelligence systems for improving utilities' load forecasting and interconnection study efforts); *see also e.g.,* Public Utils. Comm'n of Colo, Public Service Company of Colorado's Verified Application for Approval of Second Distribution System Plan, Direct Testimony of Jack W. Ihle, 22A-0547E, at 41-45 (Dec. 2024) (discussing "propensity-based" load forecasting that accounts for adoption rates of end-use electrification technologies).

87. *Load Forecasting for Modern Distribution Systems*, ELEC. POWER RSCH. INST., at 4-2 (Mar. 2013) https://www.epri.com/research/products/000000000001024377 [hereinafter EPRI].

88. *See* Tao Hong & Mohammad Shahidehpour, LOAD FORECASTING CASE STUDY, at 1-17 (Jan. 15, 2015), https://coefs.charlotte.edu/hong/files/2015/03/WTP-2015-NARUC-HONG-Shahidehpour.pdf.

Utilities have significantly improved their forecasting methodologies over time, with forecasters adjusting for more complex factors, such as the impact of weather on historic load data (e.g., normalizing models to avoid underestimating load after an abnormally cool summer lowered customers' air conditioning needs), and modeling additional variables beyond peak load to plan for power quality and asset life.[89] Forecasters have also moved beyond simply extrapolating known trends and adding in these adjustments, to "simulation" forecasts that attempt to actually model the factors that are influencing changes in demand.[90] These models have shown particular success at forecasting load growth driven by greenfield residential and commercial development, though newer iterations have improved at modeling load growth within developed areas as well.[91]

These forecasting methodologies remain far from producing a "perfect" forecast, which is in reality an unattainable goal. Utilities have generally over-forecasted load,[92] a bias that tends to produce a more expensive but more reliable system.[93] These methods could theoretically continue to meet utility load forecasters' needs if certain conditions are met:

1) future trends in load look like past trends in load, meaning forecasters can safely extrapolate based on ongoing trends, and rely on the same assumptions that informed prior forecasts;

2) sufficient excess capacity exists on the distribution system to absorb new small loads, meaning that any inaccuracy or uncertainty in forecasts (both of which are unavoidable to some degree) will not stop diffuse, smaller loads from quickly interconnecting; and

3) new large loads take longer to come online than it takes for the utility to complete system work required for interconnection, meaning that even when not specifically accounted for at a granular level in a utility's forecast, the utility still has time to complete necessary upgrades to interconnect that customer ahead of the customer's desired in-service date.

Unfortunately, these conditions aren't necessarily true in an era of widespread end-use electrification.

First, future loads don't necessarily look like past loads. End-use electrification loads can look very different from a grid planning and operations perspective than electric customers' current loads. A significant portion of EV charging, both personal light-duty EVs and fleets' light-, medium- and heavy-duty EVs can happen midday or overnight when vehicles are parked at home, at work, or at depots; and compared to current loads, they may be more flexible– and, therefore, more amenable to "shaping" to better fit the utility's system capacity – if the right price

89. *See* EPRI, *supra* note 87, at 4-3 to 4-4.

90. *See id*. at 3-12 to 3-14 (discussing the creation and use of simulation forecasting methods).

91. *Id*. at 3-13 to 3-14.

92. Mark Dyson & Alex Engel, *The Billion-Dollar Costs of Forecasting Electricity Demand*, RMI (Oct. 23, 2017), https://rmi.org/billion-dollar-costs-forecasting-electricity-demand/.

93. *See id*. Hong & Shahidehpour, *supra* note 88, at 2-2 tabl. 2-1.

signals are in place.[94] The electrification of buildings' space and water heating is also expected to increase overnight loads, as well as during the winter months, outside of the current peaks on many utility systems,[95] and may also allow for greater flexibility and demand response from heating loads as is already done for building cooling.[96] These trends can be advantageous for ratepayers as they can add load largely outside of the summer evening peaks their systems are built for, contributing to more efficient utilization and potentially downward pressure on rates,[97] but it also means potentially significant shifts in customers' energy consumption behavior to which utilities must adapt.[98]

Second, utility systems can lack the excess distribution grid capacity to absorb significant new loads, even if those loads may not contribute to system coincident peak.[99] The closer to the customer a piece of the distribution system is, the less relevant the system coincident peak is, and the more relevant the peak of the

94. Joint Compliance Filing, *supra* note 49, at Attachment 1, 21-22, 41 (showing the load profile for an average residential EV charging customer peaking overnight, and the load profile for the average fleet EV charging customer peaking midday and overnight).

95. *See* Morash, *supra* note 86, at 14 (discussing how systems with high levels of heating electrification today, such as Texas, see overnight loads stay higher during winter, particularly during cold snaps.).

96. *See* Jeff St. John, *Smart Thermostats are Helping Arizona's Grid Ride Out Brutal Heat*, CANARY MEDIA (Sep. 14, 2023), https://www.canarymedia.com/articles/grid-edge/smart-thermostats-are-helping-arizonas-grid-ride-out-brutal-heat (discussing Arizona utilities' use of smart thermostats to reduce peak demand from air conditioning loads).

97. *See Electrification Model*, *supra* note 58, at ES-2 ("Based on our analysis and modeling, we estimate that through 2035, the costs to upgrade electric distribution grids will be approximately $26 billion. Using this cost estimate, we find that electrification applies an overall downward pressure on rates across all three of the large electric utilities."); Sarah Shenstone-Harris et al., *Electric Vehicles are Driving Rates Down for All Customers*, SYNAPSE ENERGY ECON. INC. 1 (2024), https://www.synapse-energy.com/sites/default/files/Electric%20Vehicles%20Are%20Driving%20Rates%20Down%20for%20All%20Customer%20Update%20jan%202024.pdf ("We observe that over the last 11 years, EV drivers across the United States have contributed approximately $3.12 billion more than their associated costs, driving rates down for all customers. When we also include utility expenditures for EV programs, EV owners have contributed approximately $2.44 billion more in revenues than in costs."); *Proactive Grid Investment Assessment: Medium- and Heavy –Duty Vehicle Transportation Electrification*, BLACK & VEATCH 7 (Nov. 6, 2024), https://library.edf.org/AssetLink/atal4338qv8ucl8226qok35dmm170r4e.pdf?_gl=1*mlno75*_gcl_au*MTUyMjY4ODYxMi4xNzU3MTIxNDAw*_ga*MTI2NDIyMzExOC4xNzU3MTIxNDAw*_ga_2B3856Y9QW*czE3NTcxMjE0MDAkbzEkZzAkdDE3NTcxMjE0MDIkajU4JGwwJGgw [hereinafter *Proactive Grid Investment Assessment*] ("Proactive planning for M/HDV electric load can result in capital expenditure (CAPEX) savings in the long run due to reduced need to upgrade the same station to accommodate load growth into the future, when compared to sequential planning approaches.").

98. *See*, *e.g.*, N.Y. ISO, 2024 LOAD & CAPACITY DATA GOLD BOOK 9 (2024) ("The NYISO is projected to become a winter peaking system in future decades due to electrification, primarily from space heating and EVs. The timing of a switch to a winter peaking system is uncertain, and mainly influenced by the timing and composition of space heating electrification.").

99. For example, data for Pacific Gas & Electric and Southern California Edison, California's two largest utilities, show that over a third of both utilities' distribution line segments has zero excess capacity during at least one hour of the year, which does not necessarily align with the system-wide peak. *See* PACIFIC GAS & ELECTRIC, ICA & DATA PORTAL BI-ANNUAL REPORT – Q3 2025, at 20 (July 31, 2025), on file with author; Southern California Edison Company's (U 388-E) Integration Capacity Analysis (ICA) and Data Portal Biannual Report, Rulemaking No. 21-06-017 (Cal. Pub. Utils. Comm'n 8 July 31, 2025), on file with author.

specific customers that asset serves.[100] It follows that at the level of facilities that serve a single customer, such as a service line, the relevant design criterion is the peak load of that one customer. Because electrifying a fleet or multifamily or commercial building can represent a multi-megawatt load by itself, interconnecting these customers will often require distribution system investments even when excess capacity is available on the distribution system. For example, PG&E estimated that in the five years ending in 2023, more than 53% of all circuit upgrades and 28% of all substation upgrades were in response to energization requests from customers.[101] A study by Kevala on the impacts of electrification and distributed generation on California investor-owned utilities'' grids estimated that by 2035, 48% of all feeders in PG&E's territory would be at capacity, along with 36% of SCE's feeders and 22% of SDG&E's.[102] A 2023 study by National Grid and Hitachi Energy estimated that adding fourteen electric trucks to a feeder would overload 50% of the feeders in National Grid's New York service territory.[103] The addition of building electrification load from large multi-unit buildings in National Grid's territory in and around Buffalo, New York is also taxing the utility's five kilovolt system, undersized for today's load growth, and driving the company to extend sub-transmission lines to serve these customers.[104] As end use electrification trends spread beyond these early-adopting jurisdictions these trends are likely to continue for many of the utilities with older distribution systems that haven't seen significant need for expansion in recent years.

Finally, many large end-use electrification loads can materialize quickly, while the timeline to complete distribution system upgrades to serve new load can vary widely. Charging stations, whether serving a fleet or available for public charging, can in certain instances be acquired and installed in months.[105] On the building electrification side, new construction can still be a multi-year process, but some retrofits to existing structures can be significantly shorter.[106] At the same time, utilities face a number of pressures that can increase grid upgrade timelines

100. "Coincident peak" refers to the point in time when total electricity consumption across a utility system is at its maximum. A customer's individual peak load often will happen at a different time than the system coincident peak as their individual load profiles is unlikely to perfectly match that of the system as a whole.

101. San Diego Gas & Electric Company (U 902-E), Pacific Gas and Electric Company (U 39 E), and Southern California Edison Company (U 338-E) Response to Administrative Law Judge Ruling Directing Utility Responses to Questions Regarding Energization Timelines, Rulemaking No. 24-01-018, at 32 (Cal. Pub. Utils. Comm'n Apr. 22, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M530/K252/530252757.PDF.

102. *Electrification Impacts Study, supra* note 58, at ES-6.

103. *The Road to Transportation Decarbonization: Readying the Grid for Electric Fleets*, NAT'L GRID & HITACHI ENERGY, at 4 fig. ES-2 (Sep. 2023), https://www.nationalgrid.com/document/150356/download [hereinafter NAT'L GRID & HITACHI ENERGY].

104. *National Grid Urgent Upgrade Projects*, No. 24-E-0364, NAT. GRID 24-26 (Nov. 13, 2024), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60862793-0000-C755-99D5-45B99DF5AC13}.

105. *See* Cole Jermyn et al., *Building the Grid to Need*, at 14 (Jan. 2024), https://www.edf.org/sites/default/files/2024-01/BuildingGridforNeed2024.pdf.

106. *See* GUIDANCE DOCUMENT, *supra* note 86; *see also* Morash, *supra* note 86, at 14 ("While utilities have time to plan for new building developments and industrial facilities, individual building retrofits can happen virtually overnight and without warning.").

including equipment, labor, and capital availability, prioritization of other distribution system work such as reliability-driven needs, and specific circumstances of the utility such as applicable regulatory requirements, permitting timelines, and land availability. Deployment of distributed energy resources such as residential and community solar can also drive distribution upgrade needs, and work on the transmission system can put competing pressure on some staff and equipment needs. In California, long timelines for IOUs to meet customers' load interconnection requests spurred the passage of Senate Bill 410, which directed the California Public Utilities Commission (CPUC) to set targets for the average and maximum timeline for IOUs to serve these requests.[107] The large IOUs there have reported their most complex projects such as new substations taking as much as fifteen years.[108] Upgrade timelines this long make load forecasting even more challenging, as the utility must be confident far in advance that the chosen solution will provide enough additional distribution system capacity to meet the load that materializes downstream of that asset.[109]

Given how these characteristics of end-use electrification load that make the "traditional" methods of forecasting and planning for load insufficient to efficiently and effectively interconnect these loads – and facilitate the achievement of policy requirements and goals accompanying that interconnection – greater consideration is needed on the part of utilities to meet their obligation to serve this load in particular. In practice this will require a number of changes on part of utilities. As a threshold matter, utilities and their regulators will need to recognize that end-use electrification load growth can materialize in ways not adequately reflected in existing load forecasting systems, and targeted efforts may be needed. As early as 2016, when EVs still represented a miniscule share of vehicles on the road, the New York Public Service Commission directed the utilities to detail how

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107. CAL PUB. UTIL CODE §933.5 (2025).

108. Rulemaking No. 24-01-018 - Public Workshop Discussing the Development of Energization Timing Targets and Processes to Report Energization Delays, at 34, 44, 48 (Cal. Pub. Utils. Comm'n Feb. 2, 2024), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/energization/ab50_sb410-energization-workshop_02022024.pdf (stating that for SCE, distribution capacity upgrades can take 1.5-10+ years to complete, that for PG&E, distribution capacity upgrades can take 2-4 years once funding is available without delays, and that for SDG&E, distribution capacity upgrades can take 1-15 years to complete).

109. These dynamics may be even more severe for load growth from data center development, as individual data centers can have peak demands in the hundreds of megawatts or even gigawatts and developers are racing to build and interconnect them as fast as possible. *See, e.g.*, Dan Sinhoe & Zachary Skidmore, *Meta Announces 4 Million Sq. Ft., 2GW Louisiana Data Center Campus*, DATA CTR. DYNAMICS (Dec. 5, 2024), https://www.datacenterdynamics.com/en/news/meta-announces-4-million-sq-ft-louisiana-data-center-campus/ (discussing Meta's plans to build a data center with a peak demand of over two gigawatts by 2030). There remains, however, questions regarding the true magnitude and timing of data center load growth, as many of the current load requests may be duplicative applications with multiple utilities as developers seek out the cheapest, fastest interconnection. *See* Jeff St. John, *Utilities Are Flying Blind on Data Center Demand. That's a Big Problem*, CANARY MEDIA (Feb. 25, 2025) https://www.canarymedia.com/articles/utilities/utilities-are-flying-blind-on-data-center-demand-thats-a-big-problem.

they are "planning for, and enabling increased deployment of, electric vehicle supply equipment."[110] By 2017, the commission stated that it expected the utilities, as part of their biennial Distribution System Implementation Plans, to be "investigating EV-related infrastructure effects and modifications in anticipation of a potential future when the range of needs and demands for EVs is substantial."[111] Similar recognition is needed by other PUCs, tailored to the specific load growth trends anticipated in their states.

Ensuring the prudency of system investments may also require utilities to demonstrate that they relied on the best available data in their decision-making.[112] Some of utilities' existing data sources will remain relevant to forecasting end-use electrification. Building electrification, for example, encompasses both the construction of all-electric properties and the retrofitting of existing properties with electric heating and appliances.[113] Utilities' existing econometric models may already be well-suited or easily adapted to forecasting the new construction portion of this load growth given the correlation between new construction and economic conditions already baked into many load forecasts.[114] But new methodologies are needed to forecast the timeline and location of building retrofits. Emerging data sources are also available and may be particularly useful in forecasting complex loads like EVs. For example, some vehicle manufacturers collect telematics data on the vehicles they sell—including where and when they travel, where they stop, and for how long—and freely provide this data to utilities for load forecasting.[115] Some groups are adapting models initially developed for other contexts, such as traffic demand models used in transportation planning efforts, to forecast future

110. Order Adopting Distributed System Implementation Plan Guidance, No. 14-M-0101, at 25 (N.Y. Pub. Serv. Comm'n Apr. 20, 2016), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B1C7035C-B447-459A-8957-20BF3BDB6D0F}

111. Order on Distributed System Implementation Plan Filings, No. 14-M-0101, at 9 (N.Y. Pub. Serv. Comm'n Mar. 9, 2017), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={35E255DD-92FF-420B-8363-895892992103}. Illinois similarly recognized this need, as well as the opportunities EVs provide, in the Climate and Equitable Jobs Act passed in 2021. *See* 20 ILL. COMP. STAT. 627/45, at P (a)(6) and (9) (finding that "[s]tatewide adoption of electric vehicles requires increasing access to electrification for all consumers," and "[w]idespread adoption of electric vehicles can improve an electric utility's electric system efficiency and operational flexibility, including the ability of the electric utility to integrate renewable energy resources and make use of off-peak generation resources that support the operation of charging equipment.").

112. *See* Payne, *supra* note 28, at 622-627 (discussing how while widely applied the prudent investment test has never had a consistent definition, and recommending in the context of grid investments threatened by climate change that prudency should first and foremost be based on what a utility knew or should have known at the time of the investment decision).

113. Morash, *supra* note 86, at 14 (discussing how building electrification includes new construction and retrofits, and how each carries different grid planning implications for utilities).

114. *See* EPRI, *supra* note 87, at 3-13 – 3-14 (discussing examples of simulation forecasting methods that have shown promise for accurately forecasting greenfield and brownfield building construction over a five year time horizon).

115. Comments on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Infrastructure, at 5-8 (N. Y. Pub. Service Comm'n June 5, 2023), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BE0558D88-0000-C61E-8D4E-F939213F5197%7D (discussing how the company "makes vehicle movement data available to utilities at no charge for its own telematics-equipped Class 8 vehicles.").

EV charging patterns.[116] And efforts such as the Electric Power Research Institute's eRoadMap and RMI's GridUp mapping tools attempt to aggregate these and other data sources to produce EV load forecasts with varying levels of spatial and temporal granularity.[117]

Translating this data into load projections will also require utilities to make a number of assumptions about customers' behavior, assumptions that should be reasonable and defensible. EV charging, for example, can take a variety of forms with varying implications for distribution system needs. Passenger EV owners may charge at home, at public charging stations along travel routes, or at their workplace or other destinations. Commercial EV owners may charge at their base of operations, at public or semi-public charging hubs in commercial and industrial areas and along freight routes, or at their destinations like warehouses and businesses. The exact mixture of these types of charging has significant implications for not only where charging is happening, but also how. EV charging at peoples' homes and at fleet depots, for example, may be easier to shift to overnight hours that are outside of distribution system peak windows, while on-route public charging sites along highways are more likely to see opportunistic, "unmanaged" charging.[118] Regulators should consider targeted reporting requirements for utilities to identify and justify their load forecasting assumptions to ensure they are reasonable and consistent with state policy.

B. Adequacy of Service

Once a utility has identified load to be served, whether it be through a load forecast or a specific customer's interconnection request, the obligation to serve requires the utility undertake any work necessary to connect that customer to the grid and provide adequate service.[119] The requirement that utility service be "adequate" is almost universal to the statutes outlining the duty to serve across the U.S.,[120] but the word is usually not subject to further statutory definition. At most, it is often paired with other similarly ambiguous word including "safe," "just," "efficient," and "reasonable."[121] In the absence of further statutory specificity, it has generally fallen to public utility commissions and the courts to sketch the outlines of adequate service. This work cannot, and should not, be aimed towards identifying a single, unified definition of "adequacy," as the needs and expectations of customers will depend on "the type of service rendered and the needs of the area in which the utility operates."[122] For example, in the event of a widespread

116. *See* Shu Su et al., *Forecast of Electric Vehicle Charging Demand Based on Traffic Flow model and Optimal Path Planning*, 2017 19TH INT'L CONF. ON INTELLIGENT SYS. APPLICATION TO POWER SYS., https://ieeexplore.ieee.org/document/8071382.

117. *eRoadMAP*, EPRI, (last visited Sept. 4, 2025), https://eroadmap.epri.com/; *Electrification 101*, GRIDUP: AN RMIINITIATIVE, (last visited Sept. 4, 2025), https://gridup.rmi.org/.

118. *See* Joint Compliance Filing, *supra* note 49, at 41-42 (showing fleet charging peaking around 12pm and 11pm, while EV fast charger usage is consistently high between 9am and 7pm).

119. *See* Bagdanov, *supra* note 1, at 4.

120. *Id.* at 23-36 (showing the word "adequate" to appear in the obligation to serve statute of 42 states and Washington, D.C.).

121. *See id.*

122. *Duty of a Public Utility*, *supra* note 32, at 313-322.

outage, commissions may require utilities to prioritize service restoration for those customers who rely on electric service for essential medical equipment and public safety customers like fire, police, and ambulance services.[123] In areas where extreme heat is a concern, adequacy may encompass an obligation to provide sufficient service for widespread air conditioner use.[124] In the context of widespread end-use electrification, providing adequate service will require providing energy when and where it is needed on the grid in a timely manner, but the specific needs of these end uses and the emergence of new technologies should create new expectations on utilities to serve this load in ways that benefit all customers.

Much of the case law around the adequacy of service addresses utilities' obligations to minimize outages, and to notify customers when outages do occur.[125] In *Langley v. Pac. Gas & Elec. Co.*, for example, the plaintiff owned a fish hatchery and was at high risk of losing his stock of fish during a power outage.[126] He repeatedly asked his utility to notify him of outages, and a utility employee did so on multiple occasions ahead of planned outages.[127] But, no such notice came after an unplanned outage one night, and he returned to the hatchery the next morning to find almost all of his fish dead.[128] The utility argued that it was not liable for the loss, pointing to CPUC regulations that required it to "exercise 'reasonable diligence and care' to furnish a continuous and sufficient supply of electricity to its customers," and that it is not "liable for interruption or shortage or insufficiency of supply, or any loss or damage of any kind or character occasioned thereby . . . except that arising from its failure to exercise reasonable diligence."[129] The court rejected this argument, finding that even though the utility wasn't responsible for the outage itself, the CPUC regulations did not "abrogate defendant's general duty to exercise reasonable care in operating its system to avoid unreasonable risks of harm to the persons and property of its customers."[130] The utility is not expected to provide perfect, uninterrupted service, but instead must simply "act in a reasonable manner under the circumstances," which in this instance meant making a reasonable effort to give notice to customers of outages when those customers have informed the utility they require such notice "to prevent serious loss."[131]

123. *See, e.g.*, Standards for Operation, Reliability, and Safety During Emergencies and Disasters, General Order No. 166, at 7 (Cal. Pub. Utils. Comm'n May 20, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M464/K730/464730514.pdf ("In general, the utility shall set priorities so that Critical Customers, Access and Functional Needs Populations, and Essential Customers are least impacted and service is restored for the majority of customers in the shortest amount of time.").

124. Rossi & Panfil, *supra* note 72, at 1149.

125. *See id*. at 1150-52.

126. 262 P.2d 846, 847-48 (Cal. 1953).

127. *Id*. at 848.

128. *Id*. at 848-49

129. *Id*. at 849 (citing Cal. Pub. Utils. Comm'n Gen. Ord. No. 166, at 7 (May 20, 2021), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M464/K730/464730514.pdf.

130. *Langley*, 262 P.2d at 847-48 (referencing CAL. PUB. UTILS. CODE § 451).

131. *Id*. at 850. *See also* Natural Food Stores, Inc. v. Union Elec. Co., 494 S.W.2d 379, 381 (Mo. Ct. App. 1973) ("Generally speaking, an electric power company which undertakes to supply current, although not an insurer of service, has an obligation to provide a patron with adequate and continuous service...") (footnote omitted).

The application of "adequacy" to the duty to serve also generally encompasses the obligation of utilities to meet some minimum standard of service in the provision of service even in the absence of specific statutory obligations and to consider the impacts of its service on specifically situated customers where it is reasonable to do so.[132] In *Humphreys v. Central Kentucky Natural Gas Co.*, a utility was held liable for not providing enough gas at a high enough pressure to allow a florist to keep his greenhouse warm.[133] In *Kentucky Power Co. v. Kilbourn*, the court found the utility could be held liable for damages when its equipment failed to provide sufficient voltage to a customer's electric motors, causing them to overheat and start a fire.[134] And in *Lund v. Princeton*, the court found the utility liable when it replaced a transformer system that provided 240 volt service with one that provided 208 volts, which the plaintiff—a chicken hatchery owner—claimed reduced the heat produced by his incubators.[135] Although the decision to install the new transformer "was a reasonable one which defendant might determine was in the best interest of its consumers generally," the utility was at fault because it could have notified the hatchery owner of the change and give him the opportunity to take necessary steps to continue providing the necessary heat to his incubators without any harm to its remaining customers.[136] Today, PUCs often set performance standards utilities must abide by for service characteristics such as voltage,[137] but a general reasonableness standard may still apply for other service characteristics such as reliability.

Importantly, courts may distinguish between utilities' actions regarding investment and rate setting—where they are subject to the prudence standard—and their actions in the operations of their systems—where they are subject to a reasonableness standard that is less deferential to utilities.[138] In the context of end-use electrification as discussed in this article, the prudence standard may be more often applied given the focus on utility investments rather than maintenance of

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132. *See* Rossi & Panfil, *supra* note 72, at 1152.

133. 229 S.W.117, 120 (Ky. 1920) ("We do not of course mean to say that a gas company is under an absolute duty to furnish each or any of its customers the precise quantity of gas or the exact pressure needed by them, because it might not be reasonable or practicable for it to do this without discrimination, but if it known the needs of a particular customer and the quantity and pressure of gas he requires in his business it should furnish this quantity and pressure if by reasonable and practicable diligence and care under all the existing circumstances and conditions it can do so without discrimination against other customers.")

134. 307 S.W.2d 9 (Ky. 1957).

135. 85 N.W.2d 197, 200-02 (Minn. 1957).

136. *Id*. at 203.

137. *See, e.g.*, 52 Pa. Code § 57.14 (2025) (defining the allowable voltage variation for electrical service for customers of regulated electric utilities in Pennsylvania); *Electric Rule No. 2*, PAC. GAS & ELEC. CO., at 4 (2023) (setting out the minimum and maximum allowable service voltage on electric distribution circuits).

138. Massachusetts Electric Co. v. Department of Pub. Utils., 15 N.E.3d 176, 183-84 (2014) ("a utility satisfies the prudence standard where it acts in conformance with fair and prevailing utility practice. Under the reasonableness standard, a practice followed by every utility may still be unreasonable where it fails adequately to restore service following a storm in a safe and reasonably prompt manner . . . The prudence standard is limited to rate setting…") (internal citation omitted).

existing assets, but the expectation that utilities adhere to prevailing standards remains.[139]

These cases illuminate a few principles that can together define the adequacy of utility service in the context of end-use electrification. First, a utility's actions—both in providing and failing to provide service—must be prudent and/or reasonable not just in their design and intent but also in their impact on customers. Second, providing adequate, nondiscriminatory service does not require—or perhaps even allow—utilities to treat all customers equally, as "adequacy" will mean different things to different customers. And third, as utilities invest in their systems over time, they must account for how available technologies and utility practices could serve the system as a whole as well as uniquely situated customers.

1. Timeliness of Service

Applying the requirement of "adequate" service to the context of end-use electrification supports the conclusion that utilities are obligated to provide service to new customers in a reasonably timely manner. As with all applications of a "reasonableness" standard, this timeline is not fixed but depends on the specifics of both the customer's request and the utility's system. And as seen in the *Lukrawka* case, the binary question of whether a utility must extend service to a customer may be more easily justiciable than the open-ended inquiry of what timeline for that service extension is reasonable. The application of an "adequate service" requirement, however, suggests that utilities face baseline obligations to customers even in the face of distribution constraints.

Case law is understandably sparse on the topic of timeliness of distribution service, particularly when compared to that regarding utilities' obligations to minimize and mitigate outages, as evinced in *Langley*. Two factors may explain this: (1) the likelihood of complaints regarding the timeliness of service to become moot before being resolved in court, and (2) the lack of clarity in the legal obligations utilities owe to prospective customers compared to those owed to current customers. If a prospective customer applies for utility service and receives a lengthy interconnection timeline from their utility, they may decide to simply wait it out if that interconnection is still important even if far off, they may reassess whether the utility service in question is necessary, or if they have geographic flexibility they may apply for service elsewhere within the service territory or another utility's territory to seek out a shorter timeline.[140]

For those customers inclined to directly challenge a utility's interconnection timeline, there may be administrative hurdles customers are expected or required to overcome before a complaint would end up in court. The CPUC, for example, provides an "Energization Delay Reporting Form" customers can file with the commission, but they can only do so after attempting to resolve the delay with their utility directly, or if their request exceeds the maximum interconnection timeline target set by the commission—which can be up to nine years where the utility

139. *See id*. *But see Lund*, 85 N.W.2d 197, 203 (discussing the breach of an implied contract between the utility and customer to provide "reasonably adequate and continuous electrical service.").

140. This appears to be the case with emerging data center load today. *See* NAT'L GRID & HITACHI ENERGY, *supra* note 103, and accompanying text.

determines the customer's application triggers a need for a new substation.[141] And for those complaints that do reach the litigation stage, judges may be deferential to utilities as the experts on the reasonableness of system upgrade timelines on their systems. Even though utilities have an obligation to reasonably anticipate future loads and prepare their systems accordingly,[142] a judge may feel they would be going too far out on a limb to direct a utility to speed the interconnection of a specific customer whose service requires a system upgrade. This dearth of case law on the subject underscores the need for more research and scholarship on the timeliness of service, both in general and for end-use electrification in particular. This includes greater tracking of interconnection timelines for varying types of customers requesting interconnection today, and a comparison to customers' requested timelines.[143]

Even in the absence of such data or case law, however, regulators can effectuate the "adequacy of service" principles outlined above in a number of ways. The first is ensuring that utilities' capital plans and interconnection processes are sufficient to serve the number and complexity of service requests forecasted in the territory. Because serving new load requests is a core component of a utility's duty to serve, regulators should require utilities to demonstrate how their capital investment plans are reasonably consistent with the anticipated scale and pace of service requests.[144] The factors driving much of this load growth—e.g., individual

141. *See* Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays, Rulemaking No. 24-01-018, at 47 (Cal. Pub. Utils. Comm'n Sep. 17, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K806/540806654.PDF. For customers whose application triggers a need for a new or upgraded circuit or substation, this maximum timeline ranges from 684 to 3242 calendar days, or 1.9-8.9 years. *Id*.

142. *See supra* Part IV.A.

143. Efforts by the California PUC and the state's utilities in response to the directives of Senate Bill 410 represent the clearest example in the U.S. of such tracking today. *See generally* Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays, Rulemaking No. 24-01-018, at (Cal. Pub. Utils. Comm'n Sep. 17, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M540/K806/540806654.PDF.

144. The reasonableness of a utility's actions to serve new load are likely easier to outline than those related to more general, external factors such as climate change and extreme weather. A utility's liability for outages and other failures to provide service may be limited when caused by such factors. *See, e.g.*, Monolith Portland Midwest Co. v. Western Pub. Serv. Co., 142 F.2d 857, 859 (10th Cir. 1944) (describing a lightning strike that caused an outage as "clearly an act of God"); *see also* Rossi & Panfil, *supra* note 72, at 1151 ("Most states limit liability for service interruption to conduct that is, at the very minimum, negligent, though many states' regulations or approved tariffs provide some defense to customer recovery unless the utility was willfully or grossly negligent."). Some scholars have argued, however, that the overwhelming scientific evidence regarding the expected impacts of climate change are so clearly foreseeable as to overcome this hurdle. *See* Payne, *supra* note 28, at 624 ("At this point, scientists have told us far more about climate change than what utilities are taking action based upon. Utilities should be tasked with that knowledge."); Rossi & Panfil, *supra* note 72, at 1178-79 ("Just as the duty to serve requires a utility to constantly update technical standards in light of the environment in which it operates, the duty to adapt should similarly compel updates in light of what climate science makes available.").

customer electrification plans,[145] economic factors driving customer behavior,[146] and customers' regulatory obligations[147]—are not only knowable, but are the types of information that have historically been central to utilities' forecasting and planning efforts.[148] Preparing for end-use electrification, therefore, is not asking utilities to reinvent their operations; it is reasonably expecting them to adapt their operations in response to the best available information to adequately serve their customers.

Regulators should also recognize utilities' capacity to enable customers' compliance with policy requirements and goals as a threshold requirement for "timely" service. If a certain pace of interconnections of EV chargers or electrified buildings for example is needed to meet a government policy related to those sectors, the obligation to serve should include meeting that pace of need. In New York City, Local Law 154 banned fossil fuel heating in new buildings,[149] and Local Law 97 set declining limits on greenhouse gas emissions from large buildings in New York City;[150] Con Edison has reported that service requests for electric heating more than doubled from 2022 to 2023, and applications for its Clean Heat incentives from buildings covered by those regulations more than tripled in that same period.[151] In California, some fleets argued that the maximum interconnection timelines proposed by the Commission were too long because they would not allow the fleets to electrify in time to meet regulations.[152] At minimum, reasonable

145. *See, e.g.*, *Zeero- Zero Emissions, Energy Resilient Operations*, PORT OF LONG BEACH (last visited Sep. 17, 2025), https://polb.com/environment/zeero/#zero-emissions-projects ("The 2017 Clean Air Action Plan Update set the Port of Long Beach on the path to zero-emission goods movement, with a goal of transitioning terminal equipment to zero emissions by 2030 and on-road trucks by 2035."); *Everything You Need to Know About Amazon's Electric Delivery Vans from Rivian*, AMAZON (last updated June 19, 2025), https://www.aboutamazon.com/news/transportation/everything-you-need-to-know-about-amazons-electric-delivery-vans-from-rivian ("With its commitment to have at least 100,000 electric delivery vehicles on the road by 2030, Amazon will eliminate millions of metric tons of carbon per year.").

146. *See* Hussein Basma et al., *White Paper: Total Cost of Ownership of Alternative Powertrain Technologies for Class 8 Long-Haul Trucks in the United States*, INT'L COUNCIL ON CLEAN TRANSP., at ii (Apr. 2023), https://theicct.org/wp-content/uploads/2023/04/tco-alt-powertrain-long-haul-trucks-us-apr23.pdf (forecasting that battery electric trucks will be the cheapest option for long-haul operations by 2030 in all seven of the states studied)

147. *See*, *e.g.*, N.Y EDUC. LAW §3638 (McKinney 2023) (requiring all new school bus purchases in New York State to be zero-emission after July 1, 2027, and all school buses operating in the state to be zero-emission by July 1, 2035).

148. EPRI, *supra* note 87, at 3-1 (listing common inputs for utility load forecasts including customers' "utilization of new technologies, and . . . information about likely future developments, for example, opening of new factory or shopping mall, etc.").

149. N. Y. C. ADMIN. CODE, §§ 24-177.1, 24-178, 28-506 (2025)

150. *Id*. §§ 28-320, -321.

151. Consolidated Edison Company of New York, Inc. Urgent Projects Proposal, No. 24-E-2364, at 101-102 (N.Y. Pub. Serv. Comm'n Nov. 13, 2024), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={50672793-0000-C09B-BFAB-3705801008E7} ("From 2022 to 2023 the number of electric heating load letters received increased by 103%. . . . The Company observed a more than three-fold increase in the number of Local Law 97 covered buildings applying for incentives through its Clean Heat program, from 14 in 2022 to 51 in 2023.").

152. Opening Comments of Powering America's Commercial Transportation on the Proposed Decision Establishing Target Energization Time Periods and Procedure for Customers to Report Energization Delays,

interconnection timelines should be those that ensure utilities do not prevent customers from complying with requirements and goals such as these. Taking too long to interconnect a group of customers facing a regulatory compliance deadline because it was their load requests that triggered the need for grid upgrades may be unreasonable even if the utility's timeline to design and build the grid upgrades in question was reasonable. Like those customers in *Humphreys*, *Kentucky Power Co.*, and *Lund*, these are customers making service requests that may differ from those of the average customers but are still reasonable requests. They may be able to persuasively argue that utilities have access to data sources and modeling techniques that make this end-use electrification reasonably foreseeable, particularly when driven by public policy and regulations, and allow utilities to proactively begin work to serve the anticipated load rather than waiting for specific requests to begin necessary system upgrades.[153] Failure by a utility to make reasonable efforts to account for this data and prepare their systems to serve these customers may rise to the level of violating the duty to serve.

Some regulators may also be under more direct requirements to account for their state's policy goals in utility regulatory decisions. Connecticut, Washington D.C., and New York are examples of states that explicitly codify an obligation of their PUCs to consider their state climate and energy policies in their decision-making.[154] In these jurisdictions, the duty to serve manifests both "top-down" (i.e.,

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Rulemaking No. 24-01-018, at 10 (Cal. Pub. Utils. Comm'n Aug. 29, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K203/539203682.PDF (proposing alternative, shorter timelines that "are reasonable timelines because they are what is required to enable TE entities to meet their obligations under ACT, ACF and other state, local and federal regulations, as required by SB410.")

153. *See* Humphreys v. Central Ky. Nat. Gas Co., 229 S.W. 117, 120 (Ky. 1920) ("We do not of course mean to say that a gas company is under an absolute duty to furnish each or any of its customers the precise quantity of gas or the exact pressure needed by them, because it might not be reasonable or practicable for it to do this without discrimination, but if it known the needs of a particular customer and the quantity and pressure of gas he requires in his business it should furnish this quantity and pressure if by reasonable and practicable diligence and care under all the existing circumstances and conditions it can do so without discrimination against other customers."); Kentucky Power Co. v. Kilbourn, 307 S.W.2d 9, 13 (Ky. 1957); Lund v. Princeton, 85 N.W.2d 197, 200-03 (Minn. 1957); 52 PA. CODE § 57.14 (2025); *Electric Rule No. 2*, *supra* note 137.

154. CONN. GEN. STAT §16-2(m) (2025) ("Notwithstanding any provision of the general statutes, the decisions of the Public Utilities Regulatory Authority, including, but not limited to, decisions relating to rate amendments arising from the Comprehensive Energy Strategy, the Integrated Resources Plan, the Conservation and Load Management Plan and policies established by the Department of Energy and Environmental Protection, shall be guided by said strategy and plans and such policies"); D.C. CODE §34-808.02 (2025) ("In supervising and regulating utility or energy companies, the Commission shall consider the public safety, the economy of the District, the conservation of natural resources, and the preservation of environmental quality, including effects on global climate change and the District's public climate commitments."); 2019 N.Y. Laws 106 § 7(2) ("In considering and issuing permits, licenses, and other administrative approvals and decisions, including but not limited to the execution of grants, loans, and contracts, all state agencies, offices, authorities, and divisions shall consider whether such decisions are inconsistent with or will interfere with the attainment of the statewide greenhouse gas emissions limits established in article 75 of the environmental conservation law."); Order Approving Joint Proposal, As Modified, and Imposing Additional Requirements, No. 19-G-0309, 19-G-0310, & 18-M-0270, at 69-70 (N.Y. Pub. Serv. Comm'n Aug. 12, 2021), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CC550437-3EC4-4F79-8F83-CFA85C572020} (concluding "Sections 7(2) and 7(3) are applicable to the [New York Public Service] Commission's actions here," observing "the Legislature's intent that Section 7(2) of the CLCPA be broadly construed," and explaining that "Commission orders in rate cases fall within the ambit of Section 7(2)'s [and 7(3)'s] application to 'other administrative approvals' notwithstanding the absence of a direct correlation to any item provided in the list of examples").

from the regulator's obligation to align its decision-making with state law) and "bottom-up" (i.e., from the customer's regulatory compliance requirement to the utility's service obligation).

2. Quality of Service

Alongside the timeliness of service, "adequacy" also implicates the characteristics of the service customers require. These include the customer's maximum allowable load, the voltage at which they take service, and the reliability of that service, each of which can vary widely between customers. For example, hospitals and water supply facilities today are often connected to the grid by multiple feeders through "spot networks" because of the greater risk of harm from an outage than that for an average customer.[155] Utilities may owe specific duties to particularly situated customers, when the utility is aware of and can reasonably effectuate those duties.[156]

For end-use electrification customers, this includes appropriately sizing grid infrastructure in anticipation of forecasted future loads. Installing new and upgraded infrastructure that has sufficient available capacity to serve not just immediate customer needs but also reasonably likely future loads is generally considered a prudent investment;[157] in fact, utilities have an obligation to prepare for those future public needs.[158] As discussed in Part IV.A, utilities have a wide range of new data sources and analytical resources available to them to improve the temporal and geographic accuracy of their load forecasts, and an obligation to employ these tools to improve their investment decision-making.[159] Using these tools, utilities will find that additional distribution grid capacity will be needed on certain parts of their systems to serve all of the anticipated load. But they cannot simply stop at these forecasting or planning stages, content with knowing how they would serve the expected load but not actually doing so; fulfilling their duty to serve requires them to put that knowledge into practice to provide the necessary grid capacity.

In providing this capacity, utilities will need to determine where it is more cost-effective to sequentially increase capacity—upgrading assets and transferring load in response to individual or small groups of interconnection requests—and when it makes more sense to proactively complete upgrades—planning upgrades to enter service additional available headroom to serve anticipated load over a longer timeframe.[160] But as discussed above, utilities' duty to serve implicates the

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155. *See* Edvard Csanyi, *Primary and Secondary Power Distribution Systems (Layouts Explained)*, ELEC. ENG. PORTAL (last updated Jan. 18, 2025), https://electrical-engineering-portal.com/primary-secondary-distribution-systems.

156. *See* Kentucky Power Co. v. Kilbourn, 307 S.W.2d 9 (Ky. 1957); *see also* Lund v. Princeton, 85 N.W.2d 197 (Minn. 1957).

157. *See supra* Part II.B.

158. Northern Light & Power Co. v. Stacher, 109 P. 896, 903 (Cal. Dist. Ct. App. 1910) (stating that it is the "duty [of public utilities] to anticipate future needs of the public.").

159. *See supra* Part IV.A.

160. *See Proactive Grid Investment Assessment*, *supra* note 97, at 7 ("The costs and benefits related to adopting a proactive planning approach over a sequential one is largely dependent of the level of oversizing

timeliness of service, and utilities and their regulators must consider how the balance between sequential and proactive grid upgrades impacts the interconnection timeline. This includes not just the average timeline for customers as a whole, but the timelines for particularly situated customers, such as those facing regulatory compliance deadlines. Utilities do not need to meet every request of particular customers at the expense of service to the rest of their customer base—e.g. devoting more resources to accelerate the construction of a substation needed to serve a particular customer service request when that reallocation of resources will unreasonably displace or delay other necessary work. But, when utilities are on notice of their customer's service needs—including where such needs arise from an identifiable technological trend, rather than a direct request from a customer—the utility must account for those customers' needs without simply defaulting to their standard grid planning and customer interconnection processes.[161] They must take reasonable actions, and make prudent investments, to effectuate those customers' requests.

When implementing more proactive planning and construction efforts, utilities and regulators must also consider the types of service end-use electrifying customers will prefer to avoid overinvesting in the wrong types of grid assets. Some customers may have a preference for taking service at primary, rather than secondary, distribution voltages in order to operate equipment designed for higher voltages or to lower their electricity costs.[162] Similarly, utility planners will need to consider the modularity of many end-use electrification loads and the potential of these loads to grow from requiring distribution service to being better suited to taking service directly from the transmission system.[163] National Grid found in a study of anticipated electricity demand from highway EV charging between Boston, MA and Buffalo, NY that a majority of the seventy-one sites studied would eventually have peak loads above its standard limit for service at distribution voltages, with over a quarter of these sites exceeding that five megawatt limit as soon as 2030.[164] Where forecasting in accordance with best practices suggests transmission-level voltages will be needed within the forecast horizon, a utility that relies instead upon a distribution-level solution may be failing to exercise prudence.

Some electrifying customers, including public safety agencies like fire departments, police, and ambulance services electrifying their vehicle fleets, may

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employed with a proactive approach and the associated costs, which varies by planning specifications and jurisdiction.").

161. The clarity of a customer's request is also relevant, as a request with a specific site, capacity request, and timeline may more clearly obligate a utility to act than one which is more vague in its nature.

162. When customers receive high-tension service, they are generally responsible for installing and maintaining the equipment to convert their electricity from primary distribution voltages to their required service voltage; for low-tension service, in contrast, the utility is responsible for this equipment and customers pay for the additional cost through higher rates. *See* Comments of Read and Laniado, LLP on Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure, No. 23-E-0070, at 2, 5-6 (N.Y. Pub. Serv. Comm'n June 5, 2023), https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={70AB8D88-0000-CA1D-8F43-9FF784C4A29F} (explaining the Authority's preference for high-tension service for electrifying their bus depots).

163. *See* Katsh et al., *supra* note 50.

164. *Id*.

also require the same higher levels of reliability as hospitals and other critical services today, and utilities should account for this in their system planning efforts. For example, this could include additional spot networks for these agencies that have electrified their fleets to maintain emergency response services, or for heating and cooling in buildings that serve as emergency shelters during natural disasters.[165] Again, utilities cannot be expected to provide 100% reliable service to these customers, as the investment needed to approach that level of reliability is almost certainly imprudent. But, where the grid architecture can accommodate it and the customers in question are willing to pay the increased costs attributable to their service requests, utilities' duty to serve includes making prudent investments, and taking reasonable steps to forecast and serve this load, in a way that meets the specific needs of these customers.

Considerations of the "adequacy" of service must also account for emerging technologies and operational capabilities that allow the utility to provide partial service to customers when delays to providing full service is unavoidable. Flexible interconnection programs are one example of this, where utilities provide partial service to customers who traditionally would need a long-timeline grid upgrade before interconnecting.[166] For example, the utility may restrict the customer's peak load below their theoretical maximum load, or require the customer to reduce their load specifically during high-demand periods.[167] Some utilities including Pacific Gas & Electric, Southern California Edison, and Con Edison are already piloting such programs,[168] while other utilities are actively considering how to deploy them,[169] and the CPUC is exploring how to expand such pilots into

165. It should be noted that electrifying heating does not create additional safety concerns in the event of outages, as furnaces that burn natural gas or home heating oil still rely on electricity and do not work during power outages. *See* Charlotte Shuff, *Gas Myth: All Gas Appliances Work in Power Outages*, OREGON CITIZENS' UTIL. BD. (Feb. 15, 2022), https://oregoncub.org/news/blog/gas-myth-all-gas-appliances-work-in-power-outages/2489/nr-aside-main.

166. Casey Horan et al., *Let's Get Flexible: Considerations for Unlocking Grid Capacity Using Flexible Interconnection*, ENV'T DEF. FUND 6 (Feb. 2025), https://library.edf.org/AssetLink/q812pd5afr3hboi61cm503fprla5ge0p.pdf

167. *Id*. at 8-9.

168. Bridging Solutions Strategies Compliance Report Filed by Pacific Gas and Electric Company (U 39 E), Rulemaking No. 21-06-017, at Attachment A, at 3 (Cal. Pub. Utils. Comm'n Dec. 16, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M549/K805/549805932.PDF (discussing PG&E's Flex Connect program) [hereinafter PG&E Bridging Solutions]; Southern California Edison Company's (U 338-E) Plan and Compliance Report on Bridging Strategies and Solutions, Rulemaking No. 24-01-018, at 6-7 (Cal. Pub. Utils. Comm'n Dec. 16, 2024), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M550/K147/550147940.PDF (discussing SCE's Load Control Management System pilot) [hereinafter SCE Bridging Solutions]; *Department of Public Service Staff Modified Proposal for Streamlined V1G Queue Management in Electric Vehicle Make-Ready Program and Other Programs Amendment 1*, No. 18-E-0138, N.Y. PUB. SERV. COMM'N 8-9 (Dec. 17, 2024), https://dps.ny.gov/system/files/documents/2025/01/modified-proposal-for-streamlined-v1g-queue-managment.pdf (discussing Con Edison's practice of phasing interconnection of EV chargers where grid upgrade needs would delay full interconnection).

169. *See, e.g.*, Order on Refiling, Docket No. 24-0181, at 42-44 (Ill. Com. Comm'n Dec. 19, 2024), https://www.icc.illinois.gov/docket/P2023-0055/documents/359318/files/629460.pdf (acknowledging Commonwealth Edison Company's commitment to implementing flexible interconnections); *see also* Order on Refiling, Docket No. 24-0238, at 218 (Ill. Com. Comm'n Dec. 19, 2024), https://www.icc.illinois.gov/docket/P2023-0082/documents/359319/files/629463.pdf (acknowledging Ameren Illinois Company's commitment to implementing flexible interconnections).

full-scale programs in California.[170] These solutions can be used indefinitely to avoid an otherwise-necessary grid upgrade, or as part of a phased interconnection approach that increases a customer's allowable load over time as the utility completes the needed upgrades.

When used as a phased solution, flexible interconnection programs represent another tool in the toolbox for utilities to provide timely service to customers otherwise faced with lengthy grid upgrade needs, alongside temporary infrastructure solutions like mobile substations and mobile battery storage systems.[171] Some utilities facing lengthy interconnection queues are already implementing these "bridging" solutions,[172] and this need is likely to expand as end-use electrification continues to grow. For other utility territories where customers are facing these long service timelines, or are likely to see such delays given expected trends in end-use electrification, these bridging solutions may already represent the prudent option that defines the adequacy of service utilities must provide. The fact that they are not already in widespread use is not dispositive for defining reasonableness in this context, as an industry's current practice is only one piece of evidence in the prudency inquiry.[173] This inquiry must take a broader view, not just at what is generally done today, but also what can and should reasonably be done given the circumstances.[174] Not all bridging solutions will be prudent for all utilities in all instances,[175] but given the scale of the expected grid upgrade needs associated

170. Administrative Law Judge's Ruling Clarifying Next Steps for Flexible Service Connections, Modifying Phase 2 Schedule, and Requesting Party Comments, Rulemaking No. 24-01-018, at 4 (Cal. Pub. Utils. Comm'n Feb. 2, 2025), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M556/K603/556603068.PDF ("[flexible interconnections] are currently being offered to some energization customers on a case-by-case basis through form-based processes and in other cases through IOU pilots…this effort will focus on how to standardize [flexible interconnections] in simple terms that can be implemented in the very near term to avoid energization delays triggered by upstream capacity needs on the distribution system.").

171. *See, e.g.*, *Mobile Substations: A Complete Range of Flexible Solutions*, GE GRID SOLUTIONS 4, https://www.gevernova.com/grid-solutions/hvmv_equipment/files/grid-acs-l2-mobile_substations-0311-2016_03-en.pdf (detailing use cases for mobile substations, including for temporary power supply during grid upgrades and maintenance); Alex Smith, *Clean Power Unplugged: The Rise of Mobile Energy Storage*, ENERGY STORAGE NEWS (Jan. 2, 2024), https://www.energy-storage.news/clean-power-unplugged-the-rise-of-mobile-energy-storage/ (listing EV fleet charging as a use case for temporary mobile battery storage).

172. *See* PG&E Bridging Solutions, *supra* note 168; SCE Bridging Solutions, *supra* note 168.

173. *See* The T.J. Hooper, 60 F.2d 737, 740 (2d Cir. 1932) (holding that "in most cases reasonable prudence is in fact common prudence; but strictly it is never its measure; a whole calling may have unduly lagged in the adoption of new and available devices. It may never set its own tests, however persuasive be its usages. Courts must in the end say what is required; there are precautions so imperative that even their universal disregard will not excuse their omission.").

174. Texas & Pac. Ry. Co. v. Behymer, 189 U.S. 468, 470 (1903) ("What usually is done may be evidence of what ought to be done, but what ought to be done is fixed by a standard of reasonable prudence, whether it usually is complied with or not."); *see also* Rossi & Panfil, *supra* note 72, at 1179-80 ("To the extent some existing industry custom (such as a custom of looking to historical averages in planning) fails to recognize adaptation risks in energy grid planning, this does not excuse a utility's inaction or failure to take proactive operational or planning measures.").

175. Kayla Guo, *ERCOT Approves $54 Million Plan to Move CenterPoint's Mobile Generators to San Antonio*, TEX. TRIB. (Feb. 25, 2025), https://www.texastribune.org/2025/02/25/texas-power-grid-ercot-mobile-generators-centerpoint-energy-san-antoni/ (describing "mobile" generators leased by CenterPoint, which the utility did not use during major outages caused by Hurricane Beryl in 2024, leading to calls from lawmakers that the leases be found imprudent and barred from cost recovery).

with end-use electrification, providing adequate service to these electrifying customers will likely require greater consideration of these solutions than they generally receive today.

3. Glimpse of the Future: Anticipatory System Planning at FERC

The above discussion explains how distribution utilities' core legal duties include the obligations to anticipate, prepare for, and adapt to changing customer needs; and identifies ways in which these obligations manifest in the face of electric load growth. Recent history at the Federal Energy Regulatory Commission (FERC) illustrates how these obligations are implemented with respect to transmission planning.

As of this writing, regional transmission operators' generation interconnection queues are suffering from long backlogs. Data from Lawrence Berkeley National Lab found that generator interconnection requests increased every year between 2014 and 2023, and interconnection timelines for these projects have continued to grow during this same period, reaching almost five years from request to entering service in 2023.[176] These backlogs grew in response to a proliferation of interconnection requests from prospective new storage and renewable generation projects, which have grown increasingly commercially attractive as their costs have fallen. Several factors drove these backlogs, but they can be boiled down to two general categories: (1) a dearth of transmission capacity in areas rich in renewable resources; and (2) structural mismatches between RTOs' traditional interconnection processes (which were developed around large generator projects with long development timelines) and a market increasingly characterized by smaller projects reliant on fast speed-to-market.[177]

FERC has recently addressed these issues through a series of orders, including Order 1920 (and successor clarifying Orders 1920-A and 1920-B) on electric transmission planning and cost allocation.[178] These Orders demonstrate that anticipatory planning and system deployment has become an integral part of transmission utilities' existing obligations.

For example, among other things, Order 1920 examines how transmission providers conduct long-term planning for regional transmission facilities. The Order grounds this inquiry in part in FERC's obligation to ensure just, reasonable, and nondiscriminatory rates, reflecting FERC's conclusion that how utilities' costs

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176. Joseph Rand et al., *Queued Up: 2024 Edition*, LAWRENCE BERKELEY NAT'L LAB., at 10, 41 (Apr. 2024), https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_1.pdf.

177. *See* Order No. 2023, *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 P 27 (2023) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 2023]; *see also* Notice of Proposed Rulemaking, *Improvements to Generator Interconnection Procedures & Agreements,* 87 Fed. Reg. 39934, 33938-39 (July 5, 2022).

178. *See* Order No. 1920-A, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 189 FERC ¶ 61,126, 89 Fed. Reg. 97,186 (2024) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1920-A]; *see also* Order No. 2023, *supra* note 177.

are recovered through rates is inextricably bound up in how they plan for and construct infrastructure.[179]

FERC also explicitly tied transmission system planning to utilities' obligation to serve.[180] FERC found that transmission utilities' foundational duties include forward-looking infrastructure planning:

> Specifically, in this final rule, we find that there is substantial evidence to support the conclusion that the existing regional transmission planning and cost allocation processes are unjust, unreasonable, and unduly discriminatory or preferential because the Commission's existing transmission planning and cost allocation requirements do not require transmission providers to: (**1) perform a sufficiently long-term assessment of transmission needs that identifies Long-Term Transmission Needs; (2) adequately account on a forward-looking basis for known determinants of Long-Term Transmission Needs;** and (3) consider the broader set of benefits of regional transmission facilities planned to meet those Long-Term Transmission Needs.[181]

The Order goes on to articulate several ways in which utilities should discharge this aspect of their service obligation. It directs transmission providers to develop long-term scenarios, with a twenty-year forward-looking horizon, to inform infrastructure planning.[182] It further directed utilities to use "best available data inputs," including seven "factor categories," to develop these scenarios.[183] These factor categories include federal, Tribal, state, and local laws related to resource mix, demand, electrification, and decarbonization, even where the laws do not directly regulate utilities themselves;[184] as well as technological trends "including shifts toward electrification of buildings and transportation."[185]

To be clear, Order 1920 does not dictate *distribution* utilities' load forecasting obligations. It does not apply to state-jurisdictional utility distribution systems, and its connections between forward-looking planning and utilities' service obligation are derived in part from language in the Federal Power Act,[186] which does not regulate state-jurisdictional utility operations. But it is a useful corollary.

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179. *See* Order No. 1920-A, *supra* note 178, at P 61 (sustaining the "finding that the identified deficiencies in transmission planning and cost allocation processes render existing Commission-jurisdictional rates unjust and unreasonable"); *see also* South Carolina Pub. Serv. Auth. v. FERC, 762 F.3d 41, 55-59 (D.C. Cir. 2014) (holding that the Federal Power Act authorizes FERC to regulate utility "practices" that affect FERC-jurisdictional rates, and transmission planning constitutes one such practice).

180. *See* Order No. 1920, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P 447 n.996 (2024) (quoting 16 U.S.C. 824q(b)(4) [hereinafter Order No. 1920] ('The Commission shall exercise the authority of the Commission under this chapter in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.").

181. *Id.* at P 1 (emphasis added).

182. *Id.* at P 302.

183. *Id.* at PP 422, 636.

184. Order No. 1920, *supra* note 180, at PP 432, 440, 447

185. *Id.* at PP 442, 450. In its follow-up order on rehearing Order 1920-A, responding to various requests for reconsideration of Order 1920, FERC removed corporate commitments from the factor categories, but otherwise left them intact. Order No. 1920-A, *supra* note 178, at P 14.

186. *See* 16 U.S.C. § 824q(b)(4) (2018).

First, Order 1920 illustrates how load forecasting is reasonably deemed a core constituent of utilities' service obligation. Second, by prescribing specific categories of load forecasting inputs to a relatively high degree of detail, the Order suggests that this conception of utilities' service obligation is not nascent. Regulators can establish (and in FERC's case, did establish) factual records robust enough to allow this obligation to be defined and applied. Third, the Order demonstrates that incorporating anticipated policy and technology impacts into forward-looking load forecasts is a best practice. Utilities will be hard-pressed to argue that they can ignore these factors for distribution planning purposes, where they are required to consider them for transmission planning purposes. By virtue of Order 1920's broad applicability, its planning requirements will constitute (if they do not already) "good utility practice"[187] that regulators and customers can reasonably expect utilities to accomplish.

V. CONCLUSION

Adapting utility practices to serve end-use electrification is a clear case of evolution, not revolution. Most of the customers responsible for this new load will already be customers of their electricity utility looking to upsize their grid connection rather than begin it anew. But simply continuing current practices may not be sufficient for utilities to fulfill their duty to serve these customers. These loads will look different than those which utilities currently see on their systems in their timing and location, may drive new peaks or increase system utilization rates, and can be more flexible in their electricity consumption. These characteristics may make these emerging loads a significant benefit to ratepayers by supporting more efficient use of the grid as a whole, but these positives can only be realized if utilities can connect these loads to the grid efficiently and effectively.

New data collection and forecasting methods are available that can allow utilities to target the specific portions of their systems in greatest need of proactive upgrades. Data sources like vehicle telematics can give utilities invaluable insights into customers' behavior and corresponding electricity needs, but only if utilities learn how to leverage this information. Targeted bottom-up forecasting can account for how emerging loads will not show up evenly across a utility's system. And a recognition of forecasting's self-fulling nature for end-use electrification will be key for shifting utilities from a reactive to a proactive planning mindset.

187. "Good utility practice" is a widely used term of art that generally refers to industry-accepted methods, procedures, and standards by which utility companies operate. *See, e.g., Amended and Restated Operating Agreement of PJM Interconnection*, FERC Docket No. ER24-2398-000 (Dec. 1, 2024), https://www.pjm.com/pjm-files/directory/merged-tariffs/oa.pdf ("'Good Utility Practice' shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the region; including those practices required by Federal Power Act Section 215(a)(4).").

Beyond simply forecasting these new loads, meeting the duty to serve will also require utilities to actually serve this load in a timely manner, and account for the particular needs of these customers to ensure their service is of adequate quality. This includes accounting for the long construction timelines for some distribution system assets such as substations to avoid significant delays for customers seeking service. It presses utilities to adapt how they design their systems to consider the particular needs of these customers. And it suggests that they should be doing more to account for emerging practices and technologies that can take advantage of these emerging loads' particular flexibility to shorten interconnection timelines and more cost-effectively meet their electrification needs.

The coming years will be a time of significant expectations for utilities and their regulators. High energy cost burdens on customers, state policies and regulation requiring changing utility practices and investments, and the reemergence (and uncertainty) of rapid load growth are all putting pressure on utilities to do more with less. Underlying all of this is the duty to serve that fundamental obligation of utilities to provide service to customers safely, reliably, and fairly. Meeting this duty for end-use electrification loads will not be trivial, but the resources exist to do so. Actually, achieving this, however, will require regulators to hold utilities accountable to continually adapt and improve their efforts with the needs of customers in mind.